ATTACHMENT E:

Note on comments submitted

Sierra Club's comments, submitted by Mr. Robert Ukeiley, were submitted in an format that required the Division to convert their submittal through optical character recognition software The translation from image to electronic format produces errors and inconsistencies; however, the Division is including the translated text as a courtesy to interested parties to aid in the ease of reading. The Division may not have corrected all errors that occurred in the OCR translation. In all cases the Division has relied upon the original comment in its drafting of a response.

SIERRA CLUB BY ROBERT UKEILEY

<u>Comment I-A</u>:

On behalf of my clients, the Sierra Club, Kentucky Environmental Foundation (KEF), and Kentuckians For The Commonwealth and their thousands of members in Kentucky, I am writing to you to comment on the East Kentucky Power Cooperative (EKPC) J.K. Smith Generating Station (Smith) Draft Title V/Prevention of Significant Deterioration (PSD) permit (Draft Permit) for the two circulating fluidized bed (CFB) boilers and associated emission units. As these comments detail, Section A of the Draft Permit should be changed to deny authorization for the CFBs and related equipment, I.e. Emission Units 11 — 19. Denial of this permit is the right thing for <u>all</u> Kentuckians. There are cleaner, more cost effective alternatives to the proposed CFBs that will make Kentucky economically stronger. Furthermore, the Draft Permit is illegal. Even if the Kentucky Division for Air Quality (DAQ) did not deny the permit at this point, these comments detail numerous reasons why further work must be done by DAQ and EKPC and a new public comment period and public hearing must be held before DAQ can make a final decision on the Draft Permit.

I. EKPC's APPLICATION IS INCOMPLETE[1]

A. EMERGENCY GENERATOR AND FIREWATER PUMP

The Application Materials, Statement of Basis (SOB) and Draft Permit do not include any information about any emergency generator or firewater pumps. See Ex. I-1.[2] *We are not aware of any coal-fired electric generating stations that do not have any emergency generators and firewater pumps. Thus, Smith will also have to have an emergency generator(s) and/or firewater pump(s) and application material, including a BACT analysis and application forms must be submitted by EKPC.*

In considering this and other comments, it is appropriate to recall EKPC's "spotty" past when it comes to Clean Air Act permitting. See e.g. United States and Commonwealth of Kentucky v. EKPC, 06-cv-211. (E.D.Ky); Unfted States v.

EKPC, 04-34 (EDKY). As DAQ knows, the most generous interpretation one can give is that EKPC knowingly mislead DAQ and EPA by omission regarding the applicability of PSD to EKPC's Spurlock Station. See Ex. I-A-1 at 7-25. In light of this, it would be arbitrary for DAQ to simply defer to EKPC's assertions in the application materials without confirming information for itself. This applies to this issue and numerous other issues discussed below. For the emergency generator and firewater pump, if EKPC continues to deny that there is or will be an emergency generator(s) and/or emergency firewater pump(s), DAQ could conduct a site inspection to determine if there are currently any emergency generators or firewater pumps and consult with Alstom, Stanley and/or EKPC's insurance carrier to find out if there will actually be these additional emission units.

Division's Response to Comment I-A:

The Division does not concur. EKPC has confirmed that they are not requesting authorization of fossil fuel fired emergency generators or firewater pumps be installed. The project will use the existing firewater pumps, and the existing CTs will provide any emergency generator needs.

Comment I-B:

B. THE APPLICATION MATERIALS ARE MISSING OTHER ITEMS

The permit application is also incomplete because it is missing the following items:
Manufacturer's information referenced on PDF pages 157 and 160 of the East Kentucky Power Cooperative PSD application for the proposed coal-fired CFBs at the J.K. Smith plant relating to the:

Coal Crusher House Calculations;
Coal Silo I Limestone Silo Calculations;
Bed Ash Silo Calculations;
Fly Ash Silo Calculations;
Dry Scrubber Lime Silo Calculations;
Dry Scrubber Recycled Lime Silo Calculations;
Dry Scrubber Slaker Calculations.

See Ex. I-B-1. Therefore, DAQ must require EKPC to submit this information and then hold a new public comment period.

Division's Response to Comment I-B:

The Division does not concur. Emission calculations are contained in Appendix C of the application. There is no requirement that manufacturer information be filed.

Comment II-A:

II. PUBLIC PARTICIPATION WAS INADEQUATE

DAQ cannot make a final decision on the Draft Permit at this point because DAQ has failed to fully comply with the public participation requirements.

A. THE PUBLIC NOTICE DID NOT INCLUDE CLASS I INCREMENT VALUES

*The PSD permitting program includes a regulatory requirement that DAQ publicly disclose the "degree of increment consumption expected to occur" — that is, how much pollution the new plant will add in surrounding areas, and how close those areas will then be to a violation of their Local Air Quality Standard. 401 KAR 52:100 § 5(10). This provides notice to "potential commenters [who] may have an interest in different areas to be impacted," including those concerned with the health impacts of air pollution as well as businesses planning industrial projects that might prove impossible once pollution exceeds the Local Air-Quality Standard. In re. Hadson Power 14 — Buena Vista, 4 E.A.D. 258, 272 (E.A.B. 1992). See Hancock Cty. v. U.S. EPA, 1984 U.S. App. LEXIS 14024, at *3 (6th Cir. 1984) (describing "first-come first-serve" method of permitting new sources of air pollution, until increment is consumed and no additional pollution can be authorized).*

DAQ failed to provide public notice of increment consumption at Mammoth Cave National Park, Great Smoky Mountain National Park, Joyce Kilmer Slickrock, Shining Rock and Linville Gorge Class I area. See Ex. Il-A-1; SOB at 48, Table 6-8. Kentucky's Clean Air regulations require the Cabinet to provide public notice of "the degree of increment consumption expected to occur" as a result of the proposed plant. 401 KAR 52:100 § 5(10). The Cabinet failed to provide public notice of the impact of Smith's sulfur dioxide, nitrogen oxides and particulate matter pollution on the Local Air Quality Standard in five Park Class I Areas.

*EKPC has argued that the Cabinet's failure to provide that information to the public is excused because the law only required it to disclose impacts on the Local Air Quality Standard of "the county where the facility is located." Because the Mammoth Cave Area is in a different county, EKPC asserted that the Cabinet was not required to disclose the consumption of that Area's increment. That claim "reads into the [regulation] a drastic limitation that nowhere appears in the words" of the regulation itself. Hercules, Inc. v. U.S. EPA, 938 F.2d 276, 280 (D.C. Cir. 1991). The regulation's plain terms require disclosure of the "increment consumption expected to occur"; the regulation contains no language excluding "increment consumption" outside the county in which the proposed source is located. 401 KAR 52:100 § 5(10). Limiting disclosure to the source's home county disserves the basic policy behind the requirement: to allow "meaningful public participation," by ensuring that "the public [is] apprised of all [the] increment consumption as determined through the modeling analysis." In re Hadson Power, 4 E.A.D. at *35 ("Different potential commenters may have an interest in different areas to be impacted and… would reasonably be entitled* *to, available data on increment consumption at the area of their particulate concern. Otherwise, their ability to comment on the air quality impact and proposed alternatives would be severely limited.") In fact, the Franklin Court has already held that EKPC's interpretation of this regulation is unlawful. The Court held:*

> *"Kentucky's Clean Air regulations require the Cabinet to provide public notice of the "increment consumption expected to occur" as a result of the new source, 401 KAR 52:100 Sec. 5(10). The Cabinet has interpreted this regulation that this notice requirement applies only to the county in which the source will be constructed. We believe this interpretation, which has no basis in the text of the regulation, flies in the face of the purpose of the regulation; to allow meaningful public participation and a constructive dialogue among community partners as to the relative benefits and detriments of a new source of pollution... Providing notice of this increase only to a singular county when the action affects the ecological and economic health of an entire region, not to mention nearby Mammoth Cave National Park is unreasonable. We believe this lack of notice was an unfortunate oversight but one, nonetheless that compels a remand to the Cabinet for further public input."*

*Thoroughbred Opinion at *9-10, rev'd on appeal.*

*In short, the basis for this holding is that "the phrase 'degree of increment consumption'" cannot "be read as allowing for providing data at only one location." In re Hadson Power 4 E.A.D. at *35 (applying identical state and federal regulations, and remanding permit where agency failed to provide notice of increment consumption in some areas). Both by its text, and by its policy, "the regulation specifically requires [increment consumption in all areas] to be [included] in the public notice." Id. The Cabinet failed to provide that notice here, hiding impacts to one of Kentucky's treasured public lands as well as four other Class 1 areas, a potential concern to users of the park as well as to industry in the surrounding area, and thereby violating the law.*

The Cabinet is not due any deference in interpreting this notice provision because EPA wrote the notice regulation and the State simply paraphrased this federal regulation. When a state statute or regulation parrots a federal statute or regulation, courts and administrative agencies should look to federal agency rulings and case law for guidance because it is the federal government that used its knowledge, experience and expertise to craft the regulatory or statutory language at issue. Gonzalez v. Oregon, 546 U.S. 243, 257 (2006) (deciding that a federal agency was not entitled to Chevron deference in interpreting its regulation when the regulation merely paraphrased a federal statute. The Court held that "[a]n agency does not acquire special authority to interpret its own words when, instead of using its expertise and experience to formulate a regulation, it has elected merely to paraphrase the statutory language").

Therefore, DAQ should issue a new public notice which includes Smith's Class I increment consumption and then have a new public comment period.

Division's Response to Comment II-A:
The Division does not concur. The Kentucky Court of Appeals recently upheld the Division's public notices for PSD permits, and reversed the Franklin Circuit Court Thoroughbred Opinion cited above. The Kentucky Court of Appeals found that the Division's public notices comply with the requirements in 401 KAR 52:100. *Environmental and Public Protection Cabinet v. Sierra Club,* No. 2007-CI-00173, 2007-CA-001742 (Ky. App. Sept. 19, 2008) (followed by *Sierra Club v. Environmental and Public Protection Cabinet, et. al.,* Civil Action No. 07-CI-1644 (Franklin Circuit Court, Oct. 2009)). Kentucky Court decisions are binding on the Division whereas, the Environmental Appeals Board decision, cited by the Sierra Club, is not. The Division's public notices comply with all state and federal requirements. Therefore, the Division for Air Quality's interpretation that only increment consumption expected to occur in the county where the facility is located is reasonable and achieves the purpose of the public notice regulations.

Comment II-B:

B. DAQ FAILED TO MAKE ALL THE PERMITTING MATERIALS AVAILABLE TO THE PUBLIC

DAQ must hold a new public hearing before making a decision on the draft permit because DAQ failed to make all of the modeling files available as well as one other document. DAQ originally failed to provide the Class II modeling files in the Clark County public library. DAQ recognized that this was an error, which it must because an Administrative Law Judge and the Secretary has already ruled against DAQ on this issue, placed the Class II modeling files in the Clark County public library, and issued a new public notice and set a new public comment period. We appreciate this effort. However, this same violation still exists with regard to two sets of other modeling files.

First, DAQ failed to provide the nitrogen oxides (NOx) NAAQS AERMOD input files in the Clark County library. After DAQ issued the first public notice, Lois Kleffman of KEF went from here office in Madison County to the Clark County library to review and retrieve all of the permitting documents. She discovered that the Class II modeling files were not there. As noted above, in response DAQ issued a second public notice. After issued the second public notice, Ms. Kleffman again went to the Clark County library to attempt to review and retrieve all of the permitting documents. Exhibit III-1 is these files. These files do not contain the NOx NAAQS input files: See Exhibit III-1, NAAQS Modeling folder. EKPC's modeler assigns input files a "DAT" extension and output files a "LST" extension. There are no NOx NAAQS DAT files in this folder. The fact that DAQ did not provide the public with these documents raises the question of whether DAQ actually reviewed the NOx ***NAAQS*** *modeling. Furthermore, this missing data is "odd" for two reasons. One is all of the other folders contain the DAT* *input files including the NOx increment folder. See Exhibit III-1, NAAQS Modeling folder. The other is that, as explained below, there are thousands of violations of the current NOx NAAQS. Oddities to the side, failure to provide this data is a violation of the regulations that necessitates DAQ placing the missing data in the library, issuing a new public notice, and holding a new public comment period.*

We note that while it is not legally relevant, DAQ's failure to provide this data did prejudice Sierra Club, KEF and KFTC. Our modeler had to recreate an input file in order to re-run files. This took time. Modeling is time intensive and so there is only so much modeling one can physically and practically get done during a 30 day comment period. Time spent recreating files that should have been available to the public means time taken away from reviewing, analyzing, and re-running other aspects of the modeling. If DAQ truly wants to make a legally valid, protective of public health and welfare decision, it should value the massive amount of time and resources Sierra Club, KEF, and KFTC put into reviewing this draft permit and supporting materials and ensure that the public has the fully 30 days, or even longer, to review all of the material.

In addition to the missing Class II AERMOD NOx NAAQS input files, DAQ did not provide the Calmet data that is essential to evaluate the Class I modeling. As mentioned above, Lois Kleffman went to the Clark County library twice during the public comment period. Attached as Exhibit Il-B-i was the only Class I modeling data DAQ provided at the library. This does not include the Calmet data. Without the Calmet data, one cannot run CALPUFF to evaluate EKPC's claimed results with regard to Class I impacts. If all the CALPUFF data was provided, one could also use this to evaluate Class II visibility, impacts to soils and vegetation outside of Class I areas, and PM2.5 ambient impacts. Commentors raised this issue with DAQ during the public comment period but DAQ did not fix it. See Ex. lI-B-2.3 While these folders are large, it is still relatively inexpensive and easy to place these documents on an external hard drive and place them in the library for the public to review and copy. See Ex. ll-B-3. It seems that DAQ did not do this because DAQ itself never had these files and thus DAQ never reviewed and certainly never re-ran the Class I modeling. This makes DAQ's determination that the CFBs will not cause or contribute to a violation of a Class I increment arbitrary. In any event, DAQ must provide all of the Class I modeling data in the public library, issue a new public notice and set a new public comment period.

Again, while not legally relevant, we were prejudiced by DAQ's failure to provide the required data. We did eventually obtain met data from the National Park Service. See Ex. ll-B-3. However, this does not appear to be the same data that EKPC used. We cannot know that without seeing what data EKCP used by that seems to be the case. Equally important, because we had to hunt this data down ourselves, we did not have the 30 days required by law to prepare our comments. We ended up not having enough time to complete a review of the CALPUFF *modeling. Therefore, DAQ must hold a new public comment period to allow us to complete our review and submit our comments.*

Finally, Ex. I-1, which is the permit package that Ms. Kleffman found in the Clark Library during the public comment period does not contain a letter from the DAQ on 10/23/09 granting the waiver and stating the DAQ's concurrence that the emissions from the Smith project will not adversely impact the NAAQS in Clark County. See Ex. I-1.

Division's Response to Comment II-B:

The Division does not concur. The information that the Division used to review the modeling results was included in the public permit record. The Division acknowledges that the .DTA files specific to NOx was not included in NOx NAAQS modeling folder; however, as the commentor states, "Our *modeler had to recreate an input file in order to re-run files*." This fact indicates that all of the relevant information relating to input files was available in the public permit record.

The Division acknowledges that the Calmet data were not included in the draft package. However, this data is publicly available at http://www.src.com/datasets/datasets_modelready.html#REG_DOM3.

The Division acknowledges that the 10/23/2009 letter was not included with the draft package. However, as the contents of this letter were fully described on the first page of the Statement of Basis, the commenter's have not been prejudiced. The sole purpose of the "Application Summary" in the Statement of Basis was to ensure that interested persons are made aware of relevant documents and to give a brief summary of their contents.

In addition, the Division is in agreement with the Federal Land Managers (FLMs) with respect to the Class 1 modeling analysis. The Federal Land Managers determined that the impacts caused by JK Smith will not cause an adverse impact at the Class I areas. As stated in the letter dated November 24, 2009, to Mr. John Lyons from Mr. Patrick H. Reed of the National Park Service:

> *In the April 3, 2008, PSD application, EKPC included emissions from the CTs and CFBs in its Class I air quality analysis and Air Quality Related Values (AQRV) analysis. The results show that the Class I increment significant impact levels will not be exceeded at Mammoth Cave NP. The AQRV analysis shows nitrogen and sulfur deposition concentrations will be below the deposition analysis thresholds (0.01kg/ha/yr) at Mammoth Cave NP and emissions will not cause adverse visibility impacts at the park. Therefore, we do not have concerns with the proposed modifications, addition of the two CTs and two CFBs at the J.K. Smith facility.*

The Division relied upon the determination made by the FLMs, which is in accordance with 40 CFR 51:166(p)(2) and 40 KAR 51:017, Section 14(2).

Comment II-C:

C. THE PERMITTNG SUMMARY HAS THE WRONG VALUES
DAQ provided the public with a "Permit Application Summary Form" document. See Ex. I-1 at pdf 4. The document is misleading and inaccurate in that it does not reflect all of the mistakes noted in these comments. For example, it does not indicate that the source is subject to a 112(g) case by case MACT standard even though we explain below that the CFBs are subject to a 112(g) case by case MACT standard. It also has the wrong emissions values in it. For example, it says actual NOx is 80.14. But the CFBs are permitted for 1839.6 tons per year. DAQ claims that it is committed to public participation. However, this document is bad for public participation because it creates the impression that the actual emissions from the CFB5 will be very small compared to what they actually will be if DAQ decides to issue the final permit. DAQ actually refused to clarify what the values reported in the Permit Application Summary Form actually are during the public comment period. See Ex. Il-B-4. DAQ must hold a new public comment period and provide the public with a Permit Application Summary Form that is accurate and informative.

Division's Response to Comment II-C:
The Division does not concur. As stated on page 5 of the Statement of Basis: "EKPC has requested imposition of an emission limit for HCl to preclude applicability of the case-by-case MACT provisions under Section 112(g)." Therefore, Section 112(g) of the Clean Air Act does not apply.

With respect to the form listing actual emissions, the CFB project has not been constructed and is not yet operating. Therefore, actual emissions associated with the project are zero. The actual emissions listed on the form are produced from existing units at the J.K. Smith Station.

In response to the email received by Mr. Robert Ukeiley on January 10, 2010, the Division responded to Mr. Ukeiley on January 11, 2010, that comments received during the public comment period would be responded after the close of the public comment period. To be consistent and fair to all interested individuals, comments received during the public comment period are responded to in the most appropriate manner.

Comment II-D:

D. DAQ MISINFORMED THE PUBLIC ABOUT AVAILABLE INFORMATION PRIOR TO THE PUBLIC COMMENT PERIOD

Prior to the issuance of the draft permit, Sierra Club submitted initial comments a limited number of aspects of EKPC's modeling. See Ex. I-1 at pdf 410. EKPC submitted revised modeling in response to these comments. Sierra Club's counsel asked DAQ if there was a narrative that explained the changes to the modeling. It is almost impossible and certainly extremely inefficient to review changes to modeling without a narrative. There are millions of inputs and output and so *trying to figure out which inputs and outputs are different in two sets of modeling files is difficult, to say the least. DAQ told Sierra Club's counsel that there was no narrative explaining the differences in the new modeling. DAQ stated: "There was no cover letter and no narrative associated with the modeling. The disk was submitted after a meeting." Ex. ll-D-1 at 1. This, however, is not true. EKPC did submit a narrative with the new modeling that included a response to Sierra Club's comments and an explanation of the changes to the modeling. See Ex. I-i at pdf 332. However, Sierra Club did not find out that this document existed until after the public comment period. Again, this prejudiced Sierra Club in that they could have had months of additional time to review the modeling. With the limited time available, they were not able to conduct a complete review. DAQ should take responsibility for affirmatively providing the public with incorrect information and hold a new public comment period in order to ensure a complete review of the permitting documents by those who want to do so.*

Divisions Response to Comment II-D:
The Division does not concur. Ex. I-1 also includes a document titled "Revised Class II Modeling" beginning on page 337 of the file. Therefore, the document was available for public inspection during the public comment period.

Comment III-A:

Ill. AMBIENT IMPACTS ANALYSIS
A. DAQ MUST DETERMINE WHETHER SMITH WILL CAUSE OR CONTRIBUTE TO A VIOLATION OF THE PM2.5 NAAQS AND INCREMENT

According to the U.S. EPA, the PM2.5 fraction of particulate matter is distinguishable from the coarse fraction, as the smaller particles pose the "largest health risks."[4] In fact, in a 1996 report on the need to revise the PM ambient air quality standards, EPA staff found that the epidemiological data more strongly support fine particles as the surrogate for the fraction of PM most clearly associated with health effects at levels below the standards in place at that time.[5] Disturbingly, PM2.5 has been linked to premature death, in addition to aggravation of respiratory and cardiovascular disease (as indicated by increased hospital admissions for asthma, emergency room visits, absences from school or work, and restricted activity days), changes in lung function and increased respiratory symptoms, and more subtle indicators of cardiovascular health.[6] EPA also has identified lung cancer deaths, infant mortality and development problems (such as low birth weight in children) as possibly linked to PM2.5.[7]

Children are especially susceptible to the harms from PM2.5. According to the American Academy of Pediatrics, children and infants are among the most susceptible to many air pollutants, including PM2.5. Exposure to high levels of fine particulates impacts the ability of children's lungs to grow.[8] This damage is irreversible, and subjects children to greater risk of respiratory problems as adults. Children also have increased exposure compared with adults because of *higher minute ventilation and higher levels of physical activity, and thus face serious health problems from PM2.5 pollution. This susceptibility is evidenced by a recent study of PM2.5 and asthmatic children in Detroit, which emphasizes "the continued need for enforcement of existing standards."[9] In addition, the highest age-specific asthma hospitalization rate in Michigan for the years 1999 to 2001 — 46.2 per 10,000 — was for children ages 0 to 4 years of age[10].*

Older adults also are particularly susceptible to PM2.5 because of their weaker lungs and hearts. For example, studies have suggested that serious health effects, such as premature mortality, are greater among older groups of individuals.[11] Older adults also are more likely than younger ones to have preexisting respiratory and/or cardiovascular conditions that become aggravated with exposure to PM2.5.[12]

Coal plants are one of the leading sources of fine particulate matter. PM2.5 from coal plants comes in two distinct forms: primary PM2.5 is in particulate form within the boiler stack and can be collected on the filter of a filtering train, while secondary PM2.5 forms from the atmospheric interaction of various other pollutants emitted from the stack in gaseous or vapor form. Fine particle pollution from coal plants spreads over a wide area, with the majority occurring within a 500-mile radius of a plant[13] and the greatest concentrations seen nearby and within a moderate distance of a coal plant.[14]

Numerous studies have linked fine particle pollution from coal plants in particular with the negative health effects described above.[15] One study of special interest found PM2.5 pollution from the J.H. Campbell plant (located in West Olive and owned by Consumers Energy) in 2001 alone to be associated with 91-105 premature deaths (from all causes, with 12 due to cancer and 66 due to cardiopulmonary effects), 63 cases of chronic bronchitis, 33 hospital admissions, 24 asthma-related emergency room visits, 17,415 lost days of work, and 2,054 asthma attacks.[16]

The costs of PM2.5 are staggering. The serious health impacts and accompanying costs from PM2.5 pollution will burden not only individuals, but also the state through expenditure of public and employer health care dollars, lost productivity, and strains on the education system from missed school days. Luckily, the benefits from control of PM2.5 are significant. For example, a cost-benefit study completed by the U.S. EPA for the agency's recent revision of 24-hour PM2.5 standard showed from $9 billion to $76 billion in health and visibility benefits, compared to a cost of $5.4 billion for achieving the standard.[17]

As explained above, the CAA and its implementing regulations require direct control of and assurances regarding PM2.5. These requirements arise due to PM2.5's specific characteristics and resulting separate legal status vis-à-vis the NAAQS. This legal differentiation between PM2.5 and PM10 precludes the use of PM10 as a surrogate. EPA itself has stated that the basis for the 1997 guidance, *"practical difficulties" with measuring PM2.5, has been resolved. 73 Fed. Reg. at 28,340; see a/so 72 Fed. Reg. 54,112 (Sept. 12, 2007). Any assertions regarding technical limitations relative to PM2.5 are outdated. Experts in other cases likewise have demonstrated that the technical concerns behind the surrogacy approach have been resolved. In fact, EPA just proposed to repeal the surrogacy policy altogether.*

As DAQ is aware, EPA has recently confirmed that using PM10 as a surrogate for PM2.5 is seldom legally defensible. Specifically, EPA issued an order granting in part a petition seeking EPA's objection to a permit for the Trimble power plant because of the permit's lack of a PM2.5 limit ('Trimble Order"). EPA stated that:

> *EPA establishes NAAQS for certain pollutants, pursuant to Section 109 of the CAA, 42 U.S.C. § 7409. Once a NAAQS is established, the CAA sets forth a process for designating areas in the nation as attainment, nonattainment, or unclassifiable, thus triggering additional requirements consistent with the CAA and its implementing regulations. Following establishment of a NAAQS, EPA also promulgates implementation rules that provide specific details of how states must comply with the NAAQS based on the corresponding designations for areas within the state. Generally, the SIP is the primary means by which states comply with CAA requirements to attain the NAAQS. See CAA Section 110(a) and Sections 171 - 193, 42 U.S.C. § 7410(a) and § 7501 - 7515.*
>
> *On July 28, 1997, EPA revised the NAAQS for PM to add new standards for "fine" particulates, using PM2.5 as the indicator. 62 Fed. Reg. 39,852 (July 28, 1997). On October 17, 2006, EPA revised the NAAQS for both PM2.5 and PM10. 71 Fed. Reg. 61,236 (October 17, 2006). on October 23, 1997, EPA issued a memorandum from John S. Seitz regarding implementation of the 1997 standards entitled, "Interim Implementation/or the New Source Review Requirements/or PM25"(Seitz Memorandum). The Seitz Memorandum explained that sources would be allowed to use implementation of a PM10 program as a surrogate for meeting PM2.5 NSR requirements until certain technical difficulties were resolved. Seitz Memorandum at 1. On April 5, 2005, EPA issued a second guidance memorandum from Stephen D. Page entitled, "Implementation of New Source Review Requirements in PIfrl-2.5 Nonattainment Areas" (Page Memorandum), which re-affirmed the October 23, 1997 Memorandum. Page Memorandum at 1. On May 16, 2008, EPA promulgated the final rule entitled "Implementation of the New Source Review (NSR) Program for Particulate Matter Less than 2.5 Micrometers (PM2.5) (May 2008 PM25 NSR Implementation Rule). 96 [sic] Fed. Peg. 28,321 (May 16, 2008). In the preamble to that rule, EPA explained the transition to the*

PM2.5 NSR requirements beginning on page 28,340. Specifically, EPA concluded that, if a SIP-approved state is unable to implement a PSD program for the PM2.S NAAQS based on that rule, the state may continue to implement a PM1O program as a surrogate to meet the PSD program requirements for PM2.5 under the PM1O Surrogate Policy in the Seitz Memorandum [a/k/a EPA's 1997 Surrogate Policy]. 96 [sic] Fed. Peg. at 28,340-28,341.

Use of PM.10 as a Surrogate for PM2.5

When EPA issued the PM1O Surrogate Policy in 1997, the Agency did not identify criteria to be applied before the policy could be used for satisfying the PM2.5 requirements. However, courts have issued a number of opinions that are properly read as limiting the use of PM10 as a surrogate for meeting the PSD requirements for PM2.5. Applicants and state permitting authorities seeking to rely on the PM10 Surrogate Policy should consider these opinions in determining whether PM10 serves as an adequate surrogate for meeting the PM2.5 requirements in the case of the specific permit application at issue.

Courts have held that a surrogate may be used only after it has been shown to be reasonable to do so. See, e.g.. Sierra Club v. EPA. 353 F.3d 976, 982-984 (D.C. cir. 2004) (stating general principle that EPA may use a surrogate if it is "reasonable" to do so and applying analysis from National Lime Assoc v. EPA, 233 F.3d 625, 637 (D.c. cir. 2000) that is applicable to determining whether use of a surrogate is reasonable in setting emissions limitations for hazardous air pollutants under Section 112 of the Act); Mossville Envt'l Action Now v. EPA, 370 F. 3d 1232, 1242-43 (D.C. Cir. 2004) (EPA must explain the correlation between the surrogate and the represented pollutant that provides the basis for the surrogacy); 5/uewaterNetworkv. EPA, 370 F.3d 1, 18 (D.C. Cir. 2004) ("The Agency reasonably determined that regulating [hydrocarbons] would control PM pollution both because HC itself contributes to such pollution, and because HC provides a good proxy for regulating fine PM emissions"). Though these court decisions do not speak directly to the use of PM10 as a surrogate for PM2.5, EPA believes that the overarching legal principle from these decisions is that a surrogate may be used only after it has been shown to be reasonable (such as where the surrogate is a reasonable proxy for the pollutant or has a predictable correlation to the pollutant). Further, we believe that this case law governs the use of EPA's PM10 Surrogate Policy, and thus that the legal principle from the case law applies where a permit applicant or state permitting authority seeks to rely upon the PM10 surrogate policy in lieu of a PM2.5 analysis to obtain a PSD permit.

With respect to PM surrogacy in particular, there are specific issues raised in the case law that bear on whether PM10 can be considered a reasonable surrogate for PM2.5. The D.C. Circuit has concluded that PM10 was an arbitrary surrogate for a PM pollutant that is one fraction of PM10 where the use of PM10 as a surrogate for that fraction is inherently confounded" by the presence of the other fraction of PM10. ATA v. EPA, 175 F.3d 1027, 1054 (D.C. Cir. 1999) (PM10 is an arbitrary indicator for coarse PM (PM10-2.5) because the amount of coarse PM within PM10 will depend arbitrarily on the amount of fine PM (PM2.5)) In another case, however, the D.C. Circuit held that the facts and circumstances in that instance provided a reasonable rationale for using PM1O as a surrogate for PM2.5. American Farm Bureau v. EPA, 559 F.3d 512, 534-35 (D.C. Cir. 2009) (where record demonstrated that (1) PM2.5 tends to be higher in urban areas then in rural areas, and (2) evidence of health effects from coarse PM in urban areas is stronger, EPA reasoned that setting a single PM10 standard for both urban and rural areas would tend to require lower coarse PM concentrations in urban areas. The court considered the reasoning from the ATA case and accepted that the presence of PM2.5 in PM10 will cause the amount of coarse PM in PM10 to vary, but on the specific facts before it held that such variation was not arbitrary). EPA believes that these cases demonstrate the need for permit applicants and permitting authorities to determine whether PM10 is a reasonable surrogate for PM2.5 under the facts and circumstances of the specific permit at issue, and not proceed on a general presumption that PM10 is always a reasonable surrogate for PM2.5.

This case law suggests that any person attempting to show that PM10 is a reasonable surrogate for PM2.5 would need to address the differences between PM10 and PM2.5. For example, emission controls used to capture coarse particles in some cases may be less effective in controlling for PM2.5. 72 Fed. Peg. 20,586, 20,617 (April 25, 2007)... [For example], the particles that make up PM.5 may be transported over long distances while coarse particles normally travel only short distances. 70 Fed. Peg. 65,984, 65,997-98 (November 1, 2005). Under the principles in the case law, any person seeking to use the PM10 Surrogate Policy properly would need to consider these differences between PM10 and PM2.5 and demonstrate that PM10 is nonetheless an adequate surrogate for PM2.5.

Finally, the PM10 Surrogate Policy contains limits. As stated in the 1997 Seitz Memorandum, the PM10 Surrogate Policy provided that, in view of significant technical difficulties that existed in 1997. EPA believed that PM10 may properly be used as a surrogate for PM2.5 in meeting NSR requirements "until these difficulties are resolved." Seitz Memorandum at 1.... EPA noted in the May 2008 PM2.5 NSR

Implementation Rule that "these difficulties have largely been resolved." 73 Fed. Reg. at 28,340/2-3.

In this case, the record for the LG&E permit does not provide an adequate rationale to support the use of PM10 as a surrogate for PM2.5 under the circumstances for this specific permit. Overall, the record does not show how the use of the PM10 Surrogate Policy is consistent with the case law discussed above in light of the differences between PM10 and PM2.5, and does not demonstrate that the use of the Policy here falls within the limits of the Policy. For these reasons and based on the record now before EPA, the Petition is granted on the claim that the permit record does not support the use of PM10 as a surrogate for PM2.5.

Going forward and without suggesting that the following two steps are necessary or sufficient to demonstrate that PM10 is a reasonable surrogate for PM2.5, we offer the following as a possible approach to making that demonstration:

First, the source or the permitting authority establishes in the permit record a strong statistical relationship between PM10 and PM2.5 emissions from the proposed unit, both with and without the proposed control technology in operation. Without a strong correlation, there can be little confidence that the statutory requirements will be met for PM2.5 using the controls selected through a PM10 NSR analysis. A strong statistical relationship could be established in a variety of ways. In the case where the unit in question is a new unit, the applicant could rely on emissions data from similar units at the facility or at other facilities to develop a correlation that demonstrates the relationship between the two species. In the alternative, if actual emissions test data are not available for a similar unit, the applicant may be able to access and analyze the underlying source test data that has been used to develop emission factors for sources of the same type (including the type of control equipment). In developing such correlation, a simple ratio of AP42 emissions factors or of the results of a single compliance stack test would not appear to be sufficient. Instead, reasonable consideration would be given to whether and how the PM2.5/PM10 ratio may vary with source operating conditions, including variations in the fuel rate and in control equipment condition and operation. This consideration may be based on engineering analysis of the facility including the proposed control technology and/or review of existing or new emissions test data across a range of conditions at existing sources that are similar in design to the proposed unit.

Second, the source or the permitting authority demonstrates that the degree of control of PM2.5 by the control technology selected in the

> *PM10 BACT analysis will be at least as effective as the technology that would have been selected if a BACT analysis specific to PM2.5 emissions had been conducted. We present here two possible paths to accomplish this. The first would be to perform a PM2.5-specific BACT analysis, in which case the requirement is met if the control technology selected through the PM10 BACT analysis is physically the same as what is selected through the PM22.5 BACT analysis, in all respects that may affect control efficiency for PM2.5. The second path would be to perform a PM2.5-specific BACT analysis, and show that while the type and/or physical design of the control technology may be different, the efficiency for PM2.5 control of the technology selected through the PM10 BACT analysis is equal to or better than the efficiency of the technology selected through the PM2.5 BACT analysis, across the range of operating conditions that can be anticipated for the source and the control equipment. This demonstration may be based on engineering review and/or old or new emissions test data from units and control equipment similar to the proposed unit with the proposed control equipment.*
>
> *Again, these two steps are not intended to be the exclusive list of possible demonstrations that a source or permitting authority would make to show that PM10 is a reasonable surrogate for PM2.5. Sources and permitting authorities are encouraged to carefully consider the case law and the limits of the Surrogate Policy to determine what information and analysis would need to be included in the permit application and record before relying on the Surrogate Policy.*

In re Louisville Gas & Electric Co., Petition No. IV-2008-3, Order at 42-46 (EPA Adm'r Aug. 12, 2009) (footnotes omitted).91 We understand that U.S. EPA Region IV has issued guidance to state agencies directing them to explicitly justify PM10 surrogacy as directed in the Trimble Order—which DAQ has not done.

Further repudiating the Surrogate Policy, U.S. EPA has recently extended the stay of an administrative review allowing surrogacy for certain "grandfathered" sources under the PSD program. 74 Fed. Reg. 48153 (Sept. 22, 2009). The U.S. EPA also just proposed ending altogether the PM10 Surrogate Policy in states with EPA-approved PSO programs in their SIP. Id. at 48154.

DAQ's analysis of PM10 surrogacy for PM2.5 in this case does not satisfy the requirements set forth in the Trimble Order. Trimble Order at 42- 46. DAQ acknowledged that PSD was triggered for PM2.5 for this project. SOB at 4. DAQ's entire demonstration in the SOB consists of the following:

> *EKPC relied on the PM10 program requirements as a surrogate for PM2.5 consistent with the policy established by EPA in 19971 and reiterated in the 2008 PM2.5 New Source Review Rule2. By letter*

> *dated May 7, 2009 to counsel for EKPC, the Division acknowledged that continued use of the PM10 program requirements as a surrogate for PM2.5 was appropriate and concurred with EKPC's approach in its application.*
>
> *The application included a qualitative assessment of whether Smith's particulate matter emissions would have the potential to cause or contribute to a violation of the PM2.5*

SOB at 4-5. Thus, there is no attempt to address the factors EPA set forth in the Trimble decision, presumably because any attempt to do so would fail.

Neither the applicant nor DAQ has established a strong statistical relationship between PM10 and PM2.5 emissions from the proposed units, and certainly neither has utilized the methods set forth in the Trimble Order for evaluating this statistical relationship. Id. at 45. The Trimble Order does not just require a "consistent relationship between PM2.5 and PM10 emissions" as, but a "strong statistical relationship" demonstrated by one of two approaches. Id.

Despite PM2.5's unique risks, it appears that EKPC just modeled impacts from the Smith only for PM10. As explained above, U.S. EPA has established a separate NAAQS for PM2.5—twice. Under federal and state rules, PM2.5 is thus a pollutant for which modeling must be done to ensure that the NAAQS will not be violated. 40 C.F.R. § 52.21 (k)(1), (I); 401 KAR 51:017, sec. 8-11. Kentucky regulations provide that 1) the owner or operator show NAAQS will not be exceeded, 2) estimates of ambient concentrations "shall" be based on the applicable air quality models, and 3) an application for a PSD or Title V permit "shall" contain an air quality analysis for each pollutant that the source will have the potential to emit in a significant amount. 401 KAR 51:017, sec. 8-11. DAQ admits the source's potential PM2.5 emissions will exceed significant net emission rates. It is only when a NAAQS does not exist for a pollutant that the cabinet has flexibility to determine whether an air quality analysis is necessary. 401 KAR 51:017, sec. 11(1)(b). In sum, PM2.5 modeling must be done for Smith.

The PSD Applicant has not performed a modeling analysis of PM2.5 impacts from Smith as required by 40 C.F.R. 52.21(k). It has relied on the interim approach of using PM1 as a surrogate for PM2.5. The PSD Applicant has concluded that PM2.5 impacts from Smith will be well below the PM2.5 NAAQS since the PM10 impacts are below the applicable PM10 NAAQS. However, this surrogacy approach is clearly inadequate since exceedances of PM2.5 24-hour and annual PM2.5 NAAQS have been observed in the area and exceedances of these standards are often found in areas that do not violate the PM10 NAAQS. Further, US EPA has stated that "if, under a particular permitting situation, it is known that a source's emissions would cause or contribute to a violation of a PM2.5 NAAQS, it is not acceptable to apply the PM10 surrogate policy in the face of such violation" (US EPA, 2009).

The PM10 impacts discussed above were estimates using the AERMOD model and Smith's PM10 primary emissions. They do not account for the secondary formation due to chemical conversion of precursors such as NOx and SO2. Recent advances in photochemical modeling (e.g., use of fine grid resolution of 4 km or less and plume-in-grid treatment) have made a photochemical model such as CMAQ and CAMx more suitable for single source modeling. These models have recently been applied to large point sources such as power plants in Kansas, Missouri, Oklahoma and Texas. These model applications have been summarized in a presentation by EPA staff (Snyder, Erik and Bret Anderson, 2005), and this type of modeling is feasible for Smith. As discussed elsewhere in these comments, such an analysis was done in Kentucky for ozone from EGUs and so it could also be done for PM2.5.

Using PM10 as a surrogate for PM2.5 in the ambient air quality analysis is particularly inappropriate because EKPC's September 2006 application admitted at page C-32 that the PM2.5 background concentration is 15 µg/m^3, which is right at the NAAQS. In contrast, the background that EKPC claims for the PM10 annual NAAQS is only 42% of the NAAQS. Thus, PM2.5 impacts are of much greater concern than annual PM10 impacts. The revised application originally said that EKPC was going to assume that modeled PM10 impacts would be assumed to be PM2.5. Ex. I-i at 1016. Using that approach, the annual modeled impacts would be 7.87 µg/m^3 (SOB at 45) plus the background of 15 µg/m^3 equals 22.87 µg/m^3 which is well over the annual PM2.5 NAAQS. The project alone, at 6.67 µg/m^3 also causes a violation. Thus, using EKPC's methodology, the Permit must be denied because Smith will cause or contribute to a violation of the PM2.5 NAAQS. Even using the 2006- 2008 3 year average from the Lexington PM2.5 model, the background would be 13.43 µg/m^3. See http://iaspub.ep&gov/airsdata/adags.monvals?geotyoe=st&cieocode =KY&pe oinfo=st— KY—Kentucky&pol=PM25&year=2008+2007+2006&fld=monid&fld =siteid&fld=address&fld=city&fld=countv&fld=stabbr&fld=recjn&rpp=25.

Using this background and assuming that PM10 impacts equal PM2.5 impacts, Smith still causes or contributes to a violation as the source-alone's impact of 6.67µg/m^3 plus 13.43 µg/m^3 background equals 20.1µg/m^3. EKPC continued to rely on the assumption that modeled PM10 impacts equals modeled PM2.5 impacts. See Ex. I-1 at pdf 332. We note that even this approach may be non-conservative because the PM10 modeling ignores secondary PM2.5 formation. EKPC goes on to compare Smith's impacts without any background to the NAAQS but that is baseless. NAAQS analysis involves adding background to the modeled impacts. EKPC also discusses the distance between Smith and the Lexington monitor. It appears that EKPC was thinking that if the source does not cause a violation at the location of the monitoring, there are no violations. Again, that novel theory is baseless

> *In sum, DAQ's use of PM10 as a surrogate was unlawful. In agreeing to use PM10 as a surrogate for PM2.5, DAQ failed to meet the requirements for surrogacy set forth by the EPA Administrator in the Trimble Order. To correct these legal deficiencies, DAQ should abandon further efforts to use PM10 as a surrogate for PM2.5, and instead a) direct EKPC to conduct a thorough BACT analysis for PM2.5 emissions from all of this facility's emission units and points; b) mandate that a proper modeling analysis of both secondary and primary PM2.5 emissions from this facility; c) establish separate PM2.5 emissions limits throughout the facility; and 4) establish monitoring, reporting, recordkeeping, and other requirements necessary to ensure that the PM2.5 limits are being satisfied.*

Division's Response to Comment-IIIA:

The Division acknowledges the comment. Within 10 days of the close of the public comment period, EKPC submitted additional information as provided under 401 KAR 52:100, Section 2(3)(c). The information regarding the use of PM_{10} as a reasonable surrogate for $PM_{2.5}$ is included in EKPC's response and is listed as "Exhibit 1" to EKPC's response.

Although Exhibit 1 challenges the legality of EPA's Trimble Order, EKPC also provides an analysis for the use of PM_{10} as a reasonable surrogate for $PM_{2.5}$. However, EKPC notes that the significant technical difficulties previously identified by EPA that led to the establishment of EPA's PM_{10} Surrogate Policy still exist. Specifically, EKPC lists the unresolved technical issues associated with $PM_{2.5}$ quantification methods, limitations in conducting $PM_{2.5}$ Air Quality Modeling Analyses, and the lack of promulgated PSD increments for $PM_{2.5}$.

EKPC stated that the BACT for total PM_{10} would result in the same BACT determination for $PM_{2.5}$. In their response, EKPC established the "*Predictable Relationship Between $PM_{2.5}$ and PM_{10}*" and "*BACT Control for PM_{10} is also the Best Control for PM2.5*"

As published at 73 FR 28343, EPA "does not require regulation of SO_2 or NO_x as precursors to $PM_{2.5}$ under PSD until the SIP development period ends." The SIP development period is for three years after the effective date of the referenced Federal Register, May 18, 2011.

After reviewing the information submitted by EKPC relating to the reasonableness of using EPA's Surrogate Policy, the Division continues to conclude "that the degree of control of $PM_{2.5}$ by the control technology selected in the PM_{10} BACT analysis will be at least as effective as the technology that would have been selected if a BACT analysis specific to $PM_{2.5}$ had been conducted." *In the Matter of: Louisville Gas and Electric Company*, (Petition No. IV-2008-3) (August 12, 2009). Furthermore, as stated by the Division in response to the LG&E Order, "To date, EPA has not finalized rulemaking to establish increments, Significant Impact Levels (SILs), or Significant Monitoring Concentrations (SMCs) for $PM_{2.5}$ analysis. Additionally, EPA has not promulgated an approved regulatory model for $PM_{2.5}$. In absence of these key elements in a $PM_{2.5}$ analysis, the use of PM_{10} as a surrogate for $PM_{2.5}$ is reasonable and appropriate for this permit."

Comment-IIIB1:

B. OZONE
1. MODELING

The CFBs are a major source of NOx and thus must demonstrate that they do not cause or contribute to a violation of the ozone NAAQS. The currently ozone NAAQS is 75 parts per billion (ppb) although EPA has determined that the 75 ppb standard is not protective of public health and welfare and has proposed to revise it.

The atmospheric chemistry of ozone is a complex topic. Yet EKPC submitted its final ozone "analysis" on October 22, 2009. We put analysis in quotes because what EKPC submitted is devoid of scientific validity. DAQ approved the analysis the very next day on October 23, 2009. DAQ and EKPC failed to obtain EPA Region 4's approval of this "analysis." As mentioned elsewhere DAQ failed to put its approval letter in the Clark County public library. EKPC's analysis does not establish that it does not cause or contribute to a violation of the ozone NAAOS. EKPC's ozone analysis, which received less than 24 hours of review from DAQ, is little more than another attempt at the Scheffe look up tables. Dr. Scheffe himself has confirmed that this methodology is not scientifically sound. Ex. Ill-B-i. DAQ should likewise reject EKPC's methodology.

Even a decade ago, EPA has told other sources that they should use the RPM model when there is a large source or there is a particular concern regarding impacts. See Ex. III-B-2 at 1. That is the case here. Smith is over a thousand tons per year of NOx so it is a large source. In addition, because Fayette County, which borders Clark County, has a design value of 72 ppm, the current, although invalid, standard is 75 ppm and the current proposed standard is 60 to 70 ppm, there is concern regarding impacts.

EPA has more recently acknowledged that use of a regional model, as Mr. Tran suggests, is appropriate. See Ex. Ill-B-4 at 3" page. Oklahoma, Missouri, San Antonio, and Dallas/Ft. Worth have all used this approach. Id. at 9th page. EKPC has not. Therefore, DAQ must deny the permit.

We had Khanh Tran review EKPC's analysis. Mr. Tran has 30 years of experience on environmental matters including conducting computer modeling to determine the ozone impacts of a single source. His resume is attached as Ex. IlI-B-3. Mr. Tran's comment is as follows:

The proposed JK Smith Generating Station (GS) will emit large amounts of NO_X (1,925 tpy) and VOC (68 tpy). These ozone precursors react under sunlight to form ozone. EKPC has submitted a revised impact analysis in October 2009 that estimates increases in ozone formation by scaling NOX emissions from the facility using data from modeling sensitivity studies conducted by Georgia Environmental Protection Department (EPD) in support of their 8-hr ozone SIP development (December 2006 update as mentioned in the October 2009 ozone analysis). This analysis estimates that ozone increase from jK Smith will be about 0.00047 ppm

(0.47 ppb). The impact analysis submitted by EKPC is inappropriate or, at best, inadequate since it is based on the Georgia ozone modeling results that are:

1. not valid in Kentucky due to large differences in emissions of ozone precursors (NOx and VOC), terrain, land use, wind and other atmospheric conditions that affect ozone formation. Precursor emissions are different in terms of both source types and quantity. Recent VISTAS inventories show that NOx and VOC emissions from onroad mobile sources in Georgia are much larger (twice for NOx and more than 180% for VOC) than those in Kentucky (Maureen Mullen, 2003. VISTAS 2002 Draft Onroad Mobile Inventory. http://vistas-sesarm.orcj/documents/Pechan draftonroadinventory 08 280.,ppt) . Kentucky has about 33% more NOx emissions from utility than Georgia (Edward Sabo, 2003. 2002 Southeast Emissions Inventory Development http://vistassesa rm.orcjldocuments/ MACTEC draftpointa reainventor y 82803.pot)

2. based on meteorological conditions in ozone episodes that are specific to Georgia but not Kentucky,

3. based on reductions in NOx reductions at existing power plants and, thus, they are not applicable to new facilities such asJK Smith GS,

4. focused on ozone impacts in large cities such as Atlanta and Macon while the jK Smith GS facility will impact mostly rural area, and

5. more importantly, the technique based on the Georgia EPD modeling results has not been approved by regulatory agencies such as the US EPA.

Ozone precursors emitted by proposed power plants in Kentucky have been shown to cause significantly large ozone increases. In a December 2001 modeling study by Kentucky Natural Resources and Environmental Protection Cabinet, the photochemical model CMAQ was used by the US EPA to show that new power plants in Kentucky can generate 8-hour ozone increases up to 11 ppb (Kentucky NREPC, A Cumulative Assessment of the Environmental Impacts Caused by Kentucky Electric Generating Units, 2001). These large ozone increases were found to "occur in the western part of the state, close to where new power plants are proposed".

Clark County has no ozone monitor and the October 2009 ozone analysis submitted by EKPC has estimated an ozone background of 0.072 ppm that is based on the 2006-2008 measurements at the Fayette County monitoring station. While this background is below the 2008

AAQS of 0.075 ppm, it will exceed the new lower standard between 0.06 and 0.07 ppm that has recently been proposed by the US EPA. Thus, Clark County may have an ozone problem that will get worse since the proposed JK Smith GS and other planned facilities will increase ozone concentrations that will make attaining the new lower AAQS (0.06-0.07 ppm) very difficult.

A detailed modeling analysis with the-photochemical grid model CMAQ is required to accurately assess the ozone impacts from JK Smith GS and its cumulative impacts with other planned facilities in Kentucky. With readily available modeling databases such as the KY NREPC cumulative study and other recent modeling studies (e.g., the Kentucky ozone SIP and the VISTAS regional modeling), it is fairly fast and inexpensive to perform such modeling analysis. Further, in recent years, several enhancements such as the use of fine grid resolution (4 km or less) and plume-in-grid treatment have made a photochemical model such as CAMx and CMAQ more suitable for predicting ozone impacts from large NOx plumes. These models have recently been applied to large point sources such as power plants in Kansas, Missouri, Oklahoma and Texas. These model applications have been summarized in a presentation by US EPA staff (Snyder, Erik and Bret Anderson, 2005. Single Source Ozone/PM2.5 in Regional Scale Modeling and Alternate Methods. http://cleanairinfo.com/modelingworkshc/presentationsfSingle_Source_Snyder.pdf). Recently, AMI Environmental has utilized the CAMx model with a 2-km grid to assess the ozone impacts of the proposed White Stallion coal-fired plant on ozone air quality in Houston (Khanh Tran, Photochemical Modellng of Ozone Impacts of the Proposed White Stallion Energy Center Report prepared for Environmental Integrity Project, Austin, Texas. October 2009). With the modeling databases generated by Texas Commission on Environmental Quality (TCEQ) for the SIP modeling, precursor emissions from the proposed White Stallion facility have been predicted to cause maximum ozone increases over 2 ppb and several new exceedances of the 2008 AAQS of 0.075 ppm.

Thus, a detailed modeling analysis should be performed to assess the impacts of project NOx emissions on ozone air quality in Clark County and other nearby areas that may have an ozone problem since USEPA has recently proposed to lower the 2008 8- hour ozone standard of 0.075 ppm to between 0.06 and 0.07 ppm. It should be noted that, if Clark County is declared to be in non-attainment of the new lower ozone AAQS, then suitable NOx emission offsets will have to be identified.

> *EKPC has submitted in September 2009 an ozone preconstruction monitoring waiver request that has proposed the use of monitoring data at the Lexington monitor in Fayette County as background. KDAQ has approved this request in October 2009. As mentioned above, the 2006-2008 average from the Fayette County monitor of 0.072 ppm will exceed the new lower standard between 0.06 and 0.07 ppm that has recently been proposed by the US EPA. It should be noted that recent ozone monitoring at another EKPC coal-fired plant known as the Spurlock plant has shown that the 2006-2008 4t high average of 0.0762 ppm has violated the 2008 AAQS. Since Clark County currently does not an ozone monitor and the Fayette County monitor is located about 40 km from jK Smith GS, KDAQ should require ozone monitoring by JK Smith GS.*

Although ozone modeling is absolutely required, it is interesting to note that EKPC claims its impact is 0.47 ppb. SOB at 46. Even back in 1985 when the standard was 120 ppb, EPA was considering a significance level of 0.3 ppb. See Ex. lll-B-4 at 4. Even without scaling the significance level in light of the much lower current standard, EKPC's claimed impact of 0.47 ppb is above the significant level that EPA has considered. Note that EKPC and DAQ relied on Class I significant impact levels that also have not been promulgated by EPA.

As Mr. Tran mentions, ozone modeling is particularly important considering what we learned from the Spurlock units. The PSD permit for Spurlock 3 required post construction ozone modeling. See Spurlock Title V permit, Condition F.12. This monitor shows violations of the current 75 ppb NAAQS and the likely 70 ppb or less NAAQS that will come out of EPA's current review. See e.g. 3Q06 Data Audit Information, PDF page 5 (8/24/06 hours 10-17 8-hour average of 84.25 ppm); 2Q07 Data Audit (admitting there were 4 violations of the 85 ppm 8-hour ozone NAAQS). The Spurlock monitor shows that the area is non-attainment for the current 75 ppb NAAQS with a 3-year ***4th*** *high average for 2006 — 2008 of 76.2 ppb. These violations were all before the additional pollution from Spurlock 4, which began operating in April 2009.*
While we are not presented evidence to establish that Spurlock 3 caused or contributed to these violations, we are not the applicant. The regulations require that the applicant demonstrate that the source will not cause or contribute to a violation. We are saying that in light of the evidence that the Spurlock ozone monitor is monitoring violations, there is a clear need for a detailed, scientifically solid analysis of whether Smith 1 and 2 will cause or contribute to ozone NAAQS violations.

Furthermore the monitor showed violations of the then standard of 85 ppm. See 3007 Data Audit. However, it does not appear that DAQ took any action. This shows that post construction monitoring is essentially useless, and is certainly no substitute for pre-construction modeling to establish that the source will not cause or contribute to a violation.

Division's Response to Comment III-B1:

The Division concurs in part with respect to the October 23, 2009 letter. Please see the Division's Response to Comment IIB. The Division does not concur that the development of the ozone analysis and subsequent approval letter occurred in a one day timeframe. As noted by the commenter, "atmospheric chemistry of ozone is a complex topic." In the permit record, a letter to EKPC from Dr. Taimur Shaikh dated October 12, 2009, demonstrates significant technical issues to address the ozone impact analysis were discussed.

The Division does not concur with the remainder of the comment. With respect to ozone modeling, 40 CFR Part 51 Appendix W, Section 8.2.2(c) allows for a regional monitor, "If there are no monitors located in the vicinity of the source, a 'regional site' may be used to determine background. A 'regional site' is one that is located away from the area of interest but is impacted by similar natural and distant man-made sources." Thus, preconstruction monitoring can be waived in favor of regional monitoring data where appropriate.

In accordance with Appendix A to 40 CFR Part 58, the ambient air monitoring data collected by the Division at the Fayette County station meets the quality assurance requirements for PSD air monitoring. Further, ozone modeling is not required or technically feasible for individual sources. In the absence of a regulatory model for near field ozone impacts, the Division deemed the "analytical procedure" conducted by the applicant applicable for demonstration purposes in accordance with 40 CFR Part 51 Appendix W at Subsection 3.2.2. As stated in section 5.2.1 of Appendix W, the choice of method to assess the impact of an individual source depends on the nature of the source and its emissions. In addition, 401 KAR 51:052, Section 3(7), states that "the determination that a new major source or major modification will cause or contribute to a violation of a national ambient air quality standard shall be made as of the start-up date."

With respect to using the RPM model, the exhibit III-B-2 states:

> *I got some responses from other EPA Regions, and they were mostly against the use of RPM-IV. In addition to inherent problems with modeling a point source impact's on ozone, a regional pollutant, reasons against RPM were as follows:*
>
> 1. *A complex undertaking, and it's resource-intensive, e.g. need to prepare inventories along trajectory paths (but may be available if UAM modeling has been done nearby)*
> 2. *Lots of inputs needed, and many, e.g. choice of episode to model, are open to challenge by public*
> 3. *Questions on how RPM characterizes dispersion (any plume models is not going to do a good job of simulating details of plume pollutant mixing with background… but ozone chemistry is sensitive to that); may not be adequately validated*
> 4. *Some past experiences with RPM have not been convincing (Alaska, Indiana, and North Carolina). But also used in Nevada and Texas, apparently with success.*
> 5. *unclear on how much of an ozone impact should be considered a problem*

Thus, it is clear that the RPM model is not a unanimous choice for modeling ozone impacts from point sources, which does not conflict with the Division's stance on ozone modeling in the near field.

Comment III-B2:

2. EMISSION LIMIT IS NOT ADEQUATE.

We appreciate the fact that there is a mass limit in Condition 2.C.iii on page 23. This has always been required and it is encouraging to see DAQ finally complying with the law on this point. However, the limit is based on 24 hour average but the modeling is based on g/s input and hourly output. That means that actual emissions can be higher during an hour than the permitted and modeled emissions. Thus, the source has failed to demonstrate that it will not cause or contribute to violation of the ozone NAAQS. To address this, the limit needs to be changed to 210 lb/hr based on a one hour averaging time.

In addition, the limit does not apply during startup, shutdown, and malfunctions although it is required to. Because NAAQS and increments apply all the time, emission limits needed to ensure compliance with NAAQS and increment limits must apply all the time. The limit itself appears to apply all the time because it does not say that it does not apply during startup, shutdown and malfunction. On this point, it would be useful if the limit explicitly stated that it applies during startup, shutdown and malfunction.

The problem is that the permit goes on to provide that compliance shall be demonstrated by NOX CEMS and shall follow the procedures specified in 40 CFR 60.48Da. This is appropriate for the NSPS limit in 2.c.i. but not appropriate for the NAAQS compliance limit in 2.c.iii. 40 C.F.R. 60.48Da(g)(1)(2009) allows for the exclusion of emission data obtained during startup, shutdown and malfunction in calculating compliance. Furthermore, this section effectively allows for the exclusion of emission data obtained during times that are not boiler operating days. The permit must be changed to require the use of NOx CEMS data from every hour of operation to determine compliance with the NAAQS compliance limit in 2.c.iii. There must also be a data substitution methodology to fill in data that is missing. It is arbitrary for DAQ to issue a permit that assumes emissions are zero when there is no emission data because the NOx CEMS was not gathering data. We suggest that DAQ look to the 40 C.F.R. Part 75 for an approach to data substitution. However, because we cannot guess a to what Compliance Demonstration Methodology DAQ will eventually use, DAQ should issue a new draft permit and draft statement of basis and hold a new public comment period before finalizing a permit that fixes this deficiency.

The problem with this NOx limit is particularly alarming when one considers that the ozone NAAQS is based on an 8-hour averaging time. The relationship between emissions based on a 24-hour block average and ambient impacts is *random, thus making the permit arbitrary. However, this is one generality that makes the situation even worse. Ozone levels tend to peak in the late afternoon of hot sunny days. In addition, electricity demand, and thus electricity generation and thus emissions, also tend to peak in the summer months during the late afternoon. In the evening, demand and thus emissions tend to go down but so do ozone levels. This means that a 24-hour block average is particularly appropriate as it will allow Smith to have maximum emissions during the time when we need emissions to be the lowest to avoid ozone formation and then still comply with the 24 hour block average by having lower emissions during the evening hours when the lower emissions are less critical in terms of ozone formation.*

DAQ should not attempt to invoke the talisman of "baseload" to deny the above situation. Almost all coal fired power plants ramp up during peak demand periods and ramp down during the evening. This will likely be more the case with Smith which is a sub-critical unit. Compounding the situation is that there are multiple peakers at the Smith station, which will likely result in very high emissions at exactly the wrong time in terms of protecting people and the environment from damage from ozone.

Division's Response to Comment III-B2:

The Division concurs in part. With respect to averaging period, the purpose of the lb/hr limit ensures compliance with the NAAQS, which at this time is an annual standard for NO_X. Daily NO_X rates are not used for compliance with a NAAQS, daily rates are used in the Class I impacts analysis. The use of hourly estimates based upon a daily average is consistent with modeling practices and procedures.

The 210 lb/hr limit applies at all times. The NO_X limit for Unit 1 is stated in the draft permit in Section B.2.c as follows:

"Nitrogen dioxide emissions shall not exceed:

i. 1.0 lb/MWh gross energy output on a 30-day rolling average basis except during startup, shutdown, or malfunction [40 CFR 60.44Da(e)];

ii. 0.07 lbs/MMBtu on a 30-day rolling average except during start up, shut down, or malfunction [401 KAR 51:017/51:017E]; and

iii. 210 lb/hr on a 24-hour block average [NAAQS]."

While there are stated exceptions for startup, shutdown, or malfunction in i. and ii., there are no exceptions for the 210 lb/hr limit in iii.

With respect to monitoring, 40 CFR 60.48Da allows exclusions for startup, shutdown, or malfunction, and these exclusions should not be applied to the 210 lb/hr limit. Therefore, the compliance demonstration in the permit has been revised to read:

"Compliance shall be demonstrated by NO_X CEMS and shall follow the procedures specified in 40 CFR 60.48Da, with the exception that there are no exemptions from the emission limit in 2.c.iii."

Similar language has been included in the permit for carbon monoxide, particulate matter, and sulfur dioxide.

With respect to periods of missing CEMS data and data substitution procedures, paragraph B.4.a of the permit already requires that continuous monitoring systems are in compliance with 40 CFR 60.50Da and 40 CFR Part 75.

Comment III-C1:

C. SOx
1. LOAD MODELING WAS INADEQUATE
*EKPC conducted modeling for **SO2** impacts at various load levels. However, in the modeling, EKPC assumed that the exit temperature for the CFBs would be the same at 50%, 75% and 100% load, that is 333 degrees K. See Ex. III-i, Load Modeling Folder, all SO2 files. Exit temperature can affect ambient impact levels. However, there is no evidence in the permit record including the statement of basis to establish that the exit temperature will be the same at 50%, 75% and 100% load. Normally, the stack exit temperature is lower at lower loads for power plants. Therefore, EKPC either needs to document that stack exit temperature is the same at all loads with evidence from Spurlock 3 & 4 or other credible sources or EKPC needs to re-run this modeling using the correct exit temperature.*

Division's Response to Comment III-C1
The Division does not concur. For the operation of a CFB, the exit temperature is not dependent upon load. EKPC provided confirmation on the issue in the February 25, 2010 response.

Comment III-C2:

2. EMISSION LIMIT AND MONITORING FOR NAAQS COMPLIANCE IS INADEQUATE

*The draft permit's **S02** emission limit for NAAQS of 225 lb/hr for CFB1 and 229.58 lb/hr for CFB2 based on a 24-hour block average does not protect the NAAQS. EKPC put these emission rates into the AERMOD to demonstrate compliance with the NAAQS and increments in grams per second. AERMOD produces results in individual hours. These results were compared to a 3- hour averaging time significant impact level. Therefore, a truly protective emission limit would have to be based on a one second averaging time, basically instantaneous, to assure that actual emissions, and thus actual ambient impacts, do not exceed modeling emissions and modeled impacts. The most non-conservative approach that could possibly be justified is set these emission limits based on a 3-hour rolling averaging.*

In addition, the draft permit in Condition B.2.b for both CFB boilers sets the compliance demonstration as S02 CEMS following the procedures in 40 C.F.R. 60.48Da. However, this procedure allows the exclusion of S02 emission data during emergencies as that is defined in the applicable regulation. However, this emergency exception does not apply to the NAAQS. Therefore, the permit must set a different procedure for using the S02 CEMS data to determine compliance that includes all data, including replacement for missing data. Since we cannot predict what this methodology will be, DAQ must hold a new public comment period for people to review this methodology before DAQ makes a final decision on the permit.

Division's Response to Comment III-C2:
With respect to averaging times, the Division does not concur. The SO_2 NAAQS are 24-hour and annual averages. The emission limit is set to comply with the NAAQS. In addition, AERMOD can accept emission rates in either pounds per hour or gram per second. AERMOD produces results in individual hours and also as an average specified by the user. There is no regulatory basis for instantaneous monitoring or application of such in promulgated EPA methods. In addition, the assertion that a 3-hour rolling average is a more conservative approach to set emission limits than a 1-hour average is erroneous.

With respect to the emission limit applying even during emergencies, the Division concurs and has modified the permit to clarify that emergencies are not exempted.

Comment III-C3:

3. THE 24-HOUR NAAQS BACKGROUND CONCENTRATION IS INACCURATE

*EKPC did not use an accurate **S02** background concentration in the National Ambient Air Quality Standards (NAAQS) analysis. In comparing whether the facility's maximum impact would result in a 24-Hour SO2 NAAQS violation, EKPC used a background concentration of 94.32 µg/m^3. Ex. 1-1, 12- 23-09 Draft Package, as PDF p. 57. However, this concentration is lower than actual background levels, as EKPC's own monitors for the Smith Station recorded 24-hour SO2 ambient air level averages of 114.48 pg/m3 on two separate occasions.'8 Ex. III-C-3-2, 2004— 4Q04 Information, as PDF p. 12 (showing a 24-hour average of 0.043 ppm on December 19, 2004 in Madison County); Ex. III-C-3-3, 2005 — 2Q04 Information, as PDF p. 7 (showing a 24- hour average of 0.43 ppm on May 24, 2005 in Madison County).19 Monitors also recorded 24-hour **S02** ambient air level averages of 95.84 µg/m^3 on a third day. See Ex. Ill-C-3-1, 2004 — 3Q04 Information, as PDF p. 13 (showing a 24-hour average of 0.036 ppm on September 28, 2004 in Madison County). EKPC failed to describe why they ignored actual background concentrations collected by them for the Smith monitor. DAQ should not allow this. EKPC must use a background concentration of 114.48 pg/m3 for their SO2 NAAQS modeling analysis reflects actual S02 ambient air conditions.*

Division's Response to Comment III-C3:
The Division does not concur. According to 40 CFR 50.4 for SO_2, "The level of the 24-hour standard is 0.14 parts per million (ppm), not to be exceeded more than **once per calendar year**." Emphasis added. As discussed in the application, the applicant correctly chose to use the high-second-high value from the monitors for the 24-hour SO2 NAAQS compliance demonstration based on one calendar year of data.

In addition, upon the review of Exhibit III-C-3-3, the average concentration is 0.043ppm not 0.43ppm as the commenter stated.

Comment III-D1:

> *D. PM10*
>
> *1. BLUEGRASS AMRY DEPOT FUGITIVE SOURCES HAS A 112.50 METER STACK HEIGHT*
>
> *EKPC used a "stack height" of 112.50 meters for the Bluegrass Army Depot Fugitive Sources which has a source ID of BGARMY2. See e.g. Ex. III-1,PM-lncrement-Airport-R1_1990_TSP. See a/so Ex. I-1 at pdf page 360. The application and SOB do not explain how fugitive emissions can be released at 112.5 meters. DAQ either needs to explain how these fugitive emissions are released at 112.5 meters or EKPC needs to redo the PM increment and NAAQS modeling. After the new modeling is done, DAQ needs to hold a new public comment period for the public to review the new modeling prior to making a final decision on the permit.*

Division's Response to Comment III-D1:
The Division does not concur. The stack heights reported in the emissions inventory are representative of emissions from munitions destruction. The Open Burning and Open Detonation Model (OBODM) was used in modeling emissions for munitions detonation at the Bluegrass Army Depot. The user's guide for OBODM can be found at
http://www.epa.gov/scram001/dispersion_alt.htm#obodm.

Comment III-D2:

> *2. THE APPLICATANT USED AN EMISSION RATE FOR THE SMITH TURBINES 1-4 AND HAUL ROADS THAT WAS TOO LOW. WITH THE PROPER EMISSION RATE, THE SOURCE VIOLATES THE 24-HOUR PM10 INCREMENT.*
>
> *The applicant used an emission rate of 0.12600E+01 grams per second for Smith Combustion Turbines 1-4 in the PM increment and NAAQS Class II modeling.*

See Ex. III-1, PM-Increment-Airport-R1_1990_TSP; PM-Increment-Airport-R1_1991 TSP; PM-Increment-Airport-R1_1992_TSP; PM-Increment-Airport-R1_1993_TSP; PM-Increment-Airport-R1_1994_TSP; PM-Increment-Site-R1_1990_TSP; PM-lncrement-Site-R1_1991_TSP; PM-Increment-Site-R1_1992_TSP; PM-Increment-Site-R1 1993_TSP; PM-Increment-Site-R1_1994_TSP; PM-NAAQS-Airport-R1_1990_TSP; PM-NAAQSAirport-R1_1991_TSP; PM-NAAQS-Airport-R1_1992_TSP; PM-NAAQS-AirportR1_1993_TSP; PM-NAAQS-Airport-R1-1994_TSP; PM-NAAQS-SiteR1_1990_TSP; PM-NAAQS-Site-R1 1991 TSP; PM-NAAQS-Site-R1_1992_TSP; PM-NAAQS-Site-R1_1993_TSP; PM-NAAQS-Site-R1 1994_TSP. See also Ex. I-1 at PDF page 359. This modeling resulted in 84.1% of the 24-hour PM10 increment being consumed. See SOB at 45, Table 6-3.

EKPC claims the increment modeling used allowable. See Ex. I-1, PDF page 355. This is not true. Smith Combustion Turbines 1-4 have a limit of 54 pounds per hour each for particulate emissions, and even using this limit is extremely favorable to the applicant because the limit does not apply during startup, shutdown or malfunction but the NAAQS and increments do apply during startup, shutdown or malfunction. See Draft Permit at page 4, Condition B.2.h. 54 pounds per hour equals 0.680380E+01 grams per second. It appears that EKPC's mistake is based on the fact that Combustion Turbines 5-7 have a 10 pounds per hour limit which is equals 0.12600E-i-01 grams per second. See Draft Permit at 11, Condition B.2.h. Of course, EKPC cannot rely on an emission limit for units 5-7 when modeling units 1-4.

As to fugitive PM emissions from the haul roads, in their application, EKPC uses a silt content background value of 0+6 g/m2to calculate emissions. See Ex. 1-1, 12-23-09 Draft Package, as PDF p. 343. However, the application does not offer any explanation as to why this value was used. The background value of 0.6 g/m2 is consistent with the silt loading value for typical paved public roadways in AP-42, Table 13.2.1-3 (http://www.epa.gov/ttn/chief/ap42/chl3/final/c13s0201.pdf). However, the paved roads[20] of interest here are within the boundary of an industrial site and are thus industrial roadways, not public roadways. Additionally, EKPC has maintained that the haul roads are not public roads, so it does not make sense that they should treat them as such here. Ex. 1-1, 12-23-09 Draft Package, as PDF p.342. Silt loading values of industrial roads are much higher, vary greatly, and were reported elsewhere in the same chapter of AP 42.

AP-42 specifically states that the use of a tabulated default value for silt loading results in only an order-of-magnitude estimate of the emission factor for fugitive dust from truck traffic on paved roads, and therefore recommends the collection and use of site-specific silt loading data. AP-42, 13.2.1-10. In the event that a site-specific value is not available (as here), AP-42 recommends the selection of an appropriate mean value from a table listing silt loadings that were experimentally determined for a variety of industrial roads. Id. The industrial *roadway table provides a range of mean silt loading values from 7.4 to 292 g/m2. AP-42, 13.2.1-11, Table 13.2.1-4.*

EKPC's application uses a silt content background value of 0.6 g/m^2, considerably underestimating PM10 emissions from paved roads within the facility. A more appropriate value but still near the lower end of the AP-42 industrial roadway range is 9.7 g/m^2, the mean silt loading of an iron and steel production facility. AP-42, 13.2.1-11, Table 13.2.1-4. This value is appropriate not only because it is near the lower end of the industrial roadway range, but also because these facilities use coal.

Using the silt content of 0.6 g/m^2, EKPC determined a range of emission rates of the road from 0.64 to 0.84 g/s, depending on the month.[21] Ex. 1-1, 12-23-09 Draft Package as PDF p. 375. The rates vary from month to month in accordance with AP-42 to account for the presence of snow removal materials. See AP-42, Table 13.2.1-3. For modeling purposes, EKPC then divided the road into 174 segments. Ex. 1-1, 12-23-09 Draft Package as PDF p. 343. This division results in an emission rate range of 0.3700e-2 (0.0037) to 0.4800e-2 (0.0048) g/s for each road segment. Though EKPC does not describe how they determined this, this calculation along with others described below are in a spreadsheet we have labeled as Exhibit lll-D 2-1. We used the same equations as EKPC, but replaced the silt content value of 0.6 g/m2 with an appropriate but still non-conservative value of 9.7 g/m^2. In order to give a more accurate representation of emission rate, we also included an hourly precipitation factor that takes into account the effect measurable precipitation has on the particulate emissions.[22] The resulting emission rate range is 0.128e-1 (0.0128) to 0.169e-1 (0.0169) g/s, a full order of magnitude greater than the calculation in EKPC's application that uses the silt content value of 0.6 gIm2. See Ex. lll-D-2-1.

We also calculated the emission rate using the annual precipitation factor found in AP-42. See AP-42, 13.2.1-6, Equation (2). This factor recognizes that the precipitation may not occur continuously over the entire 24-hour day, unlike the hourly precipitation. AP-42, 13.2.1-6. Using the correct silt content background value of 9.7 g/m2 and the annual precipitation factor, the emission rate range was 0.2042e-1 (0.0242) to O.2694e-1 (0.02694) g/s. Ex. lll-D-2-1. Thus, the 0.6 g/m2 silt content factor does not represent the reasonable worst case emissions for this facility.

We then had an expert computer modeler, John Purdum, re-run EKPC's AERMOD modeling with the two changes to the emission rates, that is the correct emission rates for Combustion Turbines 1-4 and the correct emission rates for the haul roads. See Ex. lll-D-2-2 Declaration of John Purdum at para. 2-3. We left all other inputs into the model the same as EKPC had used, even the ones that we have identified elsewhere in these comments as in error. The modeling showed a high second high concentration of PM10 for a 24-hour period of 81.2 micrograms per cubic meter (ug/m^3). Id. at para. 3. The current PM10 24-hour increment is

30 ug/m^3. Thus, because Smith will cause an increment violation, DAQ must deny the permit.

Division's Response to Comment III-D2:
The Division does not concur. The emissions modeled for CT 1-4 are more conservative than the emissions derived from the 2006 Emissions Inventory. The commenter fails to identify the fuel type emission factor to determine whether there is an error in the established emission limitation.

With respect to the silt-loading factor, particulate matter is subject to BACT and the permit requires that roads be kept clean. Thus, the use of 0.6 g/m^2 is a reasonable estimate of the silt loading for the paved roads at Smith.

Comment III-D3:

3. EKPC FAILED TO INCLUDE SECONDARY EMISSIONS IN THE PM10 MODELING

KRS 51:017, Section 9 requires the Cabinet before issuing a permit to make a determination that: "allowable emission increases from the proposed source or modification, in conjunction with all other emission increases, reductions, including secondary emissions shall not cause or contribute to air pollution in violation of: (1) a national ambient air quality standard in an air quality control region or (2) an applicable maximum allowable increase over baseline concentration in an area, also known as a PSD increment. EKPC failed to include secondary emissions for fugitive PM10 emissions the 170 or more trucks per day that will be bringing coal, limestone and hauling ash away from the facility. We are not saying that tailpipe emissions from these trucks should be included but rather fugitive emissions on the roads that this trucks will create. This is particularly important if these trucks will be traveling down or near Irvine Road as these fugitives would likely coincide with the PM10 impacts already modeled. See I-1 at pdf page 353.

Division's Response to Comment III-D3:
The Division does not concur. The offsite fugitive emissions of PM_{10}, due to truck traffic are not required to be modeled as a source beyond the fence line. 40 CFR 51 Appendix W 5.2.2.2 (e) states:

Fugitive emissions include the emissions resulting from the industrial process that are not captured and vented through a stack but may be released from various locations within the complex.

401 KAR 51:001, Section 1(214) contains a definition of secondary emissions. Direct emissions from mobile sources are expressly exempted from the definition of secondary emissions in subparagraph (d).

Comment III-D4:

4. THE PM MODELING FAILS TO INCLUDE PROPER EMISSIONS FROM UNLOADING COAL, LIME, AND LIMESTONE FROM TRUCKS
The application acknowledges that unloading material from trucks can generate PM emissions. Ex. I-1 at pdf 651. EKPC will have trucks delivering coal, lime, and limestone. EKPC seems to have included limestone unloading in the application. Ex. I-1 at pdf 654. However, it is not in the PM increment or NAAQS modeling but there needs to be. See Ex. III-1; See also Ex. I-1 at pdf 981.

Also, EKPC used a moisture content of 10% when figuring out the emissions from the coal pile. Ex. I-1. at pdf 742. However, the AP42 formula that EKPC used has a moisture content range of 0.25 to 4.8 percent. Therefore, EKPC should either have to change the moisture content value it used to somewhere in the acceptable range and redo the modeling with the correct emission rate or the permit needs to include a condition that requires the moisture content of all delivered coal be no less than 10% and including daily monitoring and reporting of moisture content of delivered coal.

EKPC also used a control factor of 90%. Ex. I-i at pdf 742. AP42 states: "Continuous chemical treating of material loaded onto piles, coupled with watering or treatment of roadways, can reduce total particulate emissions from aggregate storage operations by up to 90 percent." Therefore, EKPC should either have to change its emission rate to remove the control factor and rerun the PM modeling with the corrected emission factor or the permit needs to include a condition requiring continuous chemical treatment of the coal in trucks prior to unloading and monitoring and reporting to ensure compliance with this condition. If it is the later, EKPC should also evaluate the VOC emissions from this continuous chemical treatment and the toxic chemicals released from this continuous chemical treatment.

Final, EKCP says that it had to multiple its emission rate for the coal pile to account for the truck unloading and then the stacking of the coal. Ex. I-i at pdf 742. EKPC failed to do that. Therefore, the emission rate should be 0.22 lbs/hr or twice whatever the emission rate is based on the above correction. EKPC must re-run the PM modeling with the corrected emission rate.

Also, there is no BACT analysis for the truck unloading for coal or lime and limestone. One BACT control technology is unloading trucks in an enclosed space. DAQ must conduct a BACT analysis of unloading coal, lime, and limestone. One control method must be consider unloading in an enclosed space with closed doors venting to a fabric filter.

In addition the application and SOB reference enclosed conveying equipment. However, there is no requirement in the draft permit that the conveying equipment must be enclosed but there needs to be.

Division's Response to Comment III-D4:
The Division does not concur. The limestone unloading was included in the modeling as LSPILE with an emission rate of 0.00037 g/s (or 0.003 lb/hr), which included the truck unloading (0.0013 lb/hr) and wind erosion (0.0017 lb/hr) emissions as calculated in Appendix C of the application. Further, particulate emissions from the unloading of the coal (CPILE 1, CPILE2, RAILUNL) and lime (SDALIME1, SDALIME2) were modeled appropriately.

In addition, the use of 10% moisture content as received by the source for the fuel is appropriate based on the fuel analysis submitted in the application.

A BACT analysis was performed for coal, limestone and lime which can be found on page 4-40 of the application. With respect to unloading for coal, lime, and limestone, the coal and limestone are stored in open storage piles. Offloading into an enclosed structure, then pushing the coal outside would likely result in more fugitive emissions than offloading it directly to the open storage pile. Lime is stored in a silo and pneumatically unloaded.

With respect to conveying equipment, as noted in the permit (Emission Unit 15), the conveying equipment will be underground.

Comment III-E:

> *E. LEAD*
> *There is no ambient impact analysis for lead. The SOB does state that the uncontrolled lead emissions are 40.26 tons per year. This is well over the 0.6 tpy significance threshold. The SOB claims that the CFBs potential to emit is 0.17 tpy, presumably based on the operation of the controls. However, the draft permit does not have enforceable conditions to assure compliance with the claimed 0.17 tpy in the SOB.*
>
> *The draft permit does have an emission factor that is used to determine compliance with the alleged synthetic minor cap for HAP5. It is 2.63E-05. Draft permit, Appendix page 2 or 3. The draft permit claims that CFB1 and 2 have heat inputs of 3000 MMBtu/hr. This is incorrect in that CFB2 is designed to be larger than CFB1 as evidenced by the higher hourly emission limits for CFB2. In any event, even using these heat input values, the PTE for CFB1 and 2 for lead is 0.691164 tpy. (2.63E-05 lbs per MMBtu * 3000 MMBtu per hour * 2 boilers * 8760 hrs per year/2000 lbs per ton = 0.691164). See also SOB at Appendix B, Lead PTE is 0.344925 tpy per unit. This is above the 0.6 tpy significant level, which is itself not protective because it is based on the old lead NAAQS. Therefore, EKPC is required to submit ambient impacts analysis using the current lead NAAQS of 0.15 ug/m3. DAQ should withdraw its completeness determination for the application until EKPC submits a complete lead ambient air quality impacts analysis. DAQ should then hold a new public comment period before deciding on whether to issue the permit.*

Division's Response to Comment III-E:
The Division concurs that the second CFB should be listed as 3061 MMBtu/hr and has made this change. It should be noted that all emission calculations for this unit were made using 3061 MMBtu/hr.

The Division has determined that potential lead emissions are less than the PSD significance threshold. While uncontrolled emissions are greater than 0.6 tons per year, the Division has determined that the controls required for BACT for PM_{10} emissions have the co-benefit of reducing potential lead emissions. As noted in Table 4-1 of the Statement of Basis, the potential to emit lead is 0.17 tons per year, whereas the PSD applicability threshold is 0.6 tons per year. The emission factor used to develop the lead emissions estimate will be confirmed during the initial stack test (Permit Section B.3.d).
For the purposes for emission estimates and inventory, the Division is requiring appropriate and sufficient testing of lead emissions.

The Division has also corrected the statement of basis to include the recent lead NAAQS of 0.15 ug/m3. The Federal Register (73 FR **67041)** states that for PSD purposes that U.S. EPA was not revising the significant emission rate, or any other PSD values. As potential lead emissions are below 0.6 tons/year lead, a BACT analysis is not required.

Comment III-F1:

F. NOx

The attempt to demonstrate that the source will not cause or contribute to a violation of the NOx NAAQS or increment is invalid for a variety of reasons.

1. EKPC HAS FAILED TO DEMONSTRATE THAT SMITH WILL NOT CAUSE OR CONTRIBUTE TO A VIOLATION OF THE NOX NAAQS

EKPC failed to even attempt to demonstrate that the Smith plant will not cause or contribute to a violation of the new NOx NAAQS. The new NOx NAAQS is 100 parts per billion (ppb) based on the 3 year average of the 98% percentile of the 1-hour daily maximum value. 75 Fed. Req. 6474 (Feb. 9, 2010). The EPA Administrator signed the rule on January 22, 2010 pursuant to a court order requiring her to do so. EPA set the NAAQS at the least protect level it had proposed so EKPC should have known that the standard would come out when it did and that it would be no less protective than it is. The rule very likely become effective before DAQ can issue the final Title V/PSD permit should it choose to do so. PSD permit requirements are effective on the promulgation date of a new or revised standard. 74 Fed. Reg. 64810, 64861 (Dec 8, 2009). The PSD requirements include but are not limited to the following: Air quality monitoring and modeling analyses to ensure that a project's emissions will not cause or contribute to a violation of any NAAQS.

We had John Purdum, an expert air modeler, re-run EKPC's NOx NAAQS modeling to determine if it established that Smith will not cause or contribute to a violation of the new 1-hour NOx NAAQS. See Ex. lll-D-2-2 at para. 4. It does not. In fact, our re-running of EKPC's NOx NAAQS modeling showed over 1900 receptors with 3 year averages of the 8th high daily maximum plus background at over 100 ppb. See Id. at para. 4. This is even without all the other flaws in EKPC's modeling identified in these comments corrected. Therefore, because EKPC has failed to demonstrate that the Smith project will not cause or contribute to a violation of the NOx NAAQS, DAQ cannot issue the final permit.

Division's Response to Comment III-F1:
The Division does not concur. As the commenter notes, the new rule was signed on January 22, 2010, and the 1-hour NO_2 standard is not effective until April 12, 2010. Therefore, the 1-hour NO2 NAAQS is not effective at the time of the issuance of this final PSD permit.

Comment III-F2:

2. EKPC USED THE WRONG EMISSION RATE FOR CT1-4

Emissions from EKPC's Combustion Turbines 1-4 was modeled at 0.14290E+02 grams per second. See e.g. Ex. III-1, NOx-NAAQS-SiteR1_1991_NOx. However, actual emissions are 124.7 lb/hr which equals 0.15712E+02 grams per second. See Ex. III-F-2-1 at Table 4. Therefore, EKPC needs to re-run the modeling with the correct emission rate and then hold a new public comment period.

Division's Response to Comment III-F2:
The Division does not concur. Exhibit III-F-2-1 is of a 2009 Emissions Test Report. JK Smith used emissions from the Kentucky Air Emissions Inventory 2006 database. From this report the total potential emissions from Combustion Turbines 1-4 is 1583.021 tpy, which equals 0.1138E+02 grams per second per Combustion Turbine. Therefore, the emission rate used for Combustion Turbines 1-4 is conservative.

Comment III-F3:

3. THE EMISSION LIMIT IS NOT ADEQUATE

We appreciate the fact that there is a NOx mass limit in Condition 2.C.iii on page 23. This has always been required and it is encouraging to see DAQ finally complying with the law on this point. However, limit is based on 24 hour average but the modeling is based on g/s input and hourly output. That means that actual emissions can be higher during an hour that the permitted and modeled emissions. Thus, the source has failed to demonstrate that it will not cause or contribute to violation of the ozone NAAQS. To address this, the limit needs to be changed to 210 lb/hr based on a one hour averaging time.

In addition, the limit does not apply during startup, shutdown, and malfunctions although it is required to. Because NAAQS and increments apply all the time, emission limits needed to ensure compliance with NAAQS and increment limits must apply all the time. The limit itself appears to apply all the time because it does not say that it does not apply during startup, shutdown and malfunction. On this point, it would be useful if the limit explicitly stated that it applies during startup, shutdown and malfunction.

The problem is that the permit goes on to provide that compliance shall be demonstrated by NOX CEMS and shall follow the procedures specified in 40 CFR 60.48Da. This is appropriate for the NSPS limit in 2.c.i. but not appropriate for the NAAQS compliance limit in 2.c.iii. 40 C.F.R. 60.48Da(g)(1)(2009) allows for the exclusion of emission data obtained during startup, shutdown and malfunction in calculating compliance. Furthermore, this section effectively allows for the exclusion of emission data obtained during times that are not boiler operating days. The permit must be changed to require the use of NOx CEMS data from every hour of operation to determine compliance with the NAAQS compliance limit in 2.c.iii. There must also be a data substitution methodology to fill in data that is missing. It is arbitrary for DAQ to issue a permit that assumes emissions are zero when there is no emission data because the NOx CEMS was not gathering data. We suggest that DAQ look to the 40 C.F.R. Part 75 for an approach to data substitution. However, because we cannot guess a to what Compliance Demonstration Methodology DAQ will eventually use, DAQ should issue a new draft permit and draft statement of basis and hold a new public comment period before finalizing a permit that fixes this deficiency.

Division's Response to Comment III-F3:
Please see the Division's Response to Comment III-B2.

Comment III-F4:

4. EKPC MUST CONDUCT LOAD MODELING FOR NOx

EKPC conducted modeling at various load levels of the CFBs for SOx and CO. See Ex. III-1, "Load Modeling" folder. However, EKPC did not conduct modeling at various load levels of the CFBs for NOx. See Ex. III-1, "Load Modeling" folder. The Statement of Basis does not explain why this is. SOB at 44-46. NOx emissions, even mass emissions, from some emission units can be considerable higher than at lower loads. Therefore, EKCP must conduct modeling at various loads, i.e. 25%, 50%, and 75%, and then hold a new public comment period for the public to review this new modeling.

Division's Response to Comment III-F4:
The Division does not concur. The applicant has sufficiently demonstrated that a decreasing load will also decrease the NOx emissions, thus the modeling demonstration at 100 percent load is appropriate.

Please refer to the response to Comment III-C1.

<u>Comment III-G:</u>

> *G. CLASS I*
>
> *EKPC did not demonstrate that it will not interfere with Air Quality Related Values. Smith will cause a greater than 5% extinction using both Method 6 and Method 2. Therefore, DAQ must require a cumulative visibility impacts analysis.*

<u>Division's Response to Comment III-G</u>:
The Division does not concur. The Federal Land Manager approved the use of Method 6 and Method 2 and determined that the visibility impacts caused by JK Smith will not cause an adverse visibility impact at the Class I areas. 40 CFR 51.166(p)2 states:

> *The Federal Land Manager and the Federal official charged with direct responsibility for management of Class I lands have an affirmative responsibility to protect the air quality related values (including visibility) of any such lands and to consider, in consultation with the Administrator, whether a proposed source or modification would have an adverse impact on such values.*

As stated in the letter dated November 24, 2009 to Mr. John Lyons from Mr. Patrick H. Reed of the National Park Service:

> *In the April 3, 2008, PSD application, EKPC included emissions from the CTs and CFBs in its Class I air quality analysis and Air Quality Related Values (AQRV) analysis. The results show that the Class I increment significant impact levels will not be exceeded at Mammoth Cave NP. The AQRV analysis shows nitrogen and sulfur deposition concentrations will be below the deposition analysis thresholds (0.01kg/ha/yr) at Mammoth Cave NP and emissions will not cause adverse visibility impacts at the park. Therefore, we do not have concerns with the proposed modifications, addition of the two CTs and two CFBs at the J.K. Smith facility.*

The Division is in agreement with the Federal Land Managers.

<u>Comment III-H1:</u>

> *H. ADDITIONAL IMPACTS ANALYSIS*
> *1. SOILS AND VEGETATION*
>
> *The Statement of Basis says that because neither the primary nor secondary NAAQS were exceeded, no impairment to soils and vegetation is expected to occur. SOB at 51. The SOB is inadequate because it does not explain which NAAQS it is referring to. Use the current ozone NAAQS to determine whether there will be demand to vegetation is inadequate because EPA has determined*

that the current secondary ozone NAAQS is inadequate and has proposed a new secondary NAAQS. Furthermore, EKPC did not do any ozone modeling. EKPC must model ozone and compare it to the proposed secondary NAAQS, as supported by the latest ozone Integrated Science Assessment, to determine if there will be adverse impacts. The same is true with the secondary PM2.5, SOx and NOx NAAQS. EPA is in the process of revising these standards that are no longer scientifically defensible. Therefore, EKPC needs to review the latest science on these impacts. The final Integrated Science Assessments and Risk and Exposure Assessments for secondary PM2.5 and SOx and NOx are good sources for EKPC to begin its research. The NOx/SOx one is here http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=201485 *and is hereby incorporated herein by reference.*

EKPC also completely failed to evaluate how its mercury, lead, selenium and other toxic metals will affect soils. EKPC must gather information about current contamination levels and there model the additional contamination Smith will add and compared that to an appropriate standard.

DAQ continues to use the 1980 EPA Screening procedures. In light of the new NOx/SOx secondary ISA, this is no longer defensible. In any event, as we have explained before, the standards in the 1980 EPA Screening document are based on cumulative impacts. DAQ's allowance of comparison of cumulative standards to a single sources impacts is arbitrary.

Division's Response to Comment III-H1:
The Division does not concur. With respect to "which NAAQS it is referring to", the only relevant standard would be those standards that were in effect at the time the document was written. These standards are summarized in Table 6-1 of the Statement of Basis.

Ozone, $PM_{2.5}$, SO_2, and NO_2 modeling is not required to ensure compliance with proposed standards before they are not finalized.

Furthermore, JK Smith performed a Toxic Air Pollutant Risk Assessment to demonstrate compliance with 401 KAR 63:020, which states that:

No owner or operator shall allow any affected facility to emit potentially hazardous matter or toxic substances in such quantities or duration as to be harmful to the health and welfare of humans, animals and plants.

With respect to the use of the 1980 EPA Screening procedures, the Division does not concur that the ISA is a replacement. Neither document establishes mandatory standards, but rather provides guidance and information only. Even taken as guidance, the two documents do not serve the same purpose. The 1980 EPA Screening procedures are screening procedures. The ISA report was developed for the purpose of providing a basis for NAAQS development. As noted at the website link provided by the commenter:

EPA has released the final report, Integrated Science Assessment (ISA) for Oxides of Nitrogen and Sulfur - Ecological Criteria. This final ISA document represents a concise synthesis and evaluation of the most policy-relevant science and will ultimately provide the scientific bases for EPA's decision on retaining or revising the current secondary standards for NO_2 and SO_2.

With respect to the comment that "DAQ's allowance of comparison of cumulative standards to a single source's impacts is arbitrary", as noted in Section 3.1 of "A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals", Final Report:

"No simple procedure is currently available to deal with the impact of a single source on acid precipitation. Acid precipitation presents a regional problem involving long-range transport which makes the impact of a single-source difficult to isolate."

Later in that same section, the report states:

"No simple models are currently available to estimate the impacts on ozone concentrations of emissions of volatile organic compounds (VOC) from a single source. EPA is currently developing means other than modeling to deal with VOC emissions and ozone. It appears likely that an emission management approach will be taken. When this approach has been completed it could probably be used to review new sources for impacts on air quality related values. Meanwhile, the minimum reported concentrations at which vegetative damage occurs are presented here but no method for their use is given and no significance levels for VOC emissions have been developed."

It should be noted that modeled concentrations do not exceed secondary NAAQS standards, which are set to protect the public welfare from any known or anticipated adverse effects of a pollutant.

401 KAR 51:017 provides that the "owner or operator shall provide an analysis of the impairment to visibility, soils and vegetation that would occur as a result of the source or modification." DAQ's interpretation and application of 401 KAR 51:017 has been upheld in other permitting actions. *See Sierra Club v. Environmental & Public Protection Cabinet and Thoroughbred Generating Company, LLC* File No. DAQ-26003-037, 26048-037, Secretary's Findings, Conclusion of Law and Final Order, at 22-23 (Aril 11, 2006).

<u>Comment III-H2:</u>

2. CONSTRUCTION IMPACTS AND SECONDARY GROWTH

EKPC failed to consider secondary growth emissions for fugitive PM10 emissions the 170 or more trucks per day that will be bringing coal, limestone and hauling ash away from the facility. We are not saying that tailpipe emissions from these trucks should be included but rather fugitive emissions on the roads that this trucks will create. This is particularly important if these trucks will be traveling *down or near Irvine Road as these fugitives would likely coincide with the PM10 impacts already modeled. See I1 at pdf page 353. Emissions including fugitives from coal trucks.*

The SOB states that construction vehicles will use low sulfur fuel and are not expected to significantly affect ambient air quality. This "analysis" is inadequate because it is both unsupported and wrong. As EPA describes, diesel engines like those in heavy-duty trucks are huge sources of harmful particulate matter, as well as pollutants that contribute to ozone formation (NOx), acid rain (SO2), and global warming (GHGs). See U.S. EPA, "Diesel Exhaust in the United States." The list of public health studies detailing the negative impacts of diesel-fueled mobile sources is endless. As the American Lung Association describes on its website:

> *Diesel exhaust has been linked in numerous scientific studies to cancer, the exacerbation of asthma and other respiratory diseases. A draft report released by the US EPA in February 1998 indicated that exposure to even low levels of diesel exhaust is likely to pose a risk of lung cancer and respiratory impairment. And in August 1998, the State of California decided that there was enough evidence to list the particulate matter in diesel exhaust as a toxic air contaminant - a probable carcinogen requiring action to reduce public exposure and risk.*
>
> *Dozens of studies link airborne fine particle, such as those in diesel exhaust, to increased hospital admissions for respiratory diseases, chronic obstructive lung disease, pneumonia, heart disease and up to 60,000 premature deaths annually in the US.23*

Nowhere do the analyses supporting the Draft Permit include an assessment of harmful pollution from diesel engines associated with the Proposed Coal Plant. Nor does the Draft Permit in any way require control of such pollution beyond the use of "low sulfur fuel," which is in no way any enforceable requirement, despite the availability of controls. The Draft Permit cannot issue without such an analysis and without controls on the vehicles that are critical to the Project's operations.

Division's Response to Comment III-H2:

The Division concurs in part. The Division concurs that the statement, "Construction vehicles will use low sulfur fuel and are not expected to significantly affect ambient air quality", should not be included in the Statement of Basis and has been removed. As previously noted, the definition of secondary emissions expressly exempts vehicle tailpipe emissions [401 KAR 51:001, Section 1(214)(d)]. For that same reason, the Division does not concur that there is any requirement to assess vehicle tailpipe emissions.

Comment III-H3:

3. NON-CLASS I VISIBILITY

Using Viscreen I, EKPC determined that Smith will adversely impact visibility in the Red River Gorge. DAQ should require EKPC to use CALPUFF to conduct a further analysis rather than continuing to rely on a screening model.

Division's Response to Comment III-H3:
The Division does not concur. Although Red River Gorge exceeded the VISCREEN Level 1 threshold for visibility, EKPC demonstrated that the project would not adversely impact visibility in the Red River Gorge by performing a Level 2 analysis using the procedures outlined in the *Workbook for Plume Visual Impact and Analysis,* which can be obtained here: http://www.epa.gov/nscep/.

Comment III-I1:

I. CARBON MONOXIDE
1. LOAD MODELING WAS INADEQUATE
EKPC conducted modeling for carbon monoxide impacts at various load levels. However, in the modeling, EKPC assumed that the exit temperature for the CFBs would be the same at 50%, 75% and 100% load, that is 333 degrees K. See Ex, Ill-i, Load Modeling Folder, all CO files. Exit temperature can affect ambient impact levels. However, there is no evidence in the permit record including the statement of basis to establish that the exit temperature will be the same at 50%, 75% and 100% load. Normally, the stack exit temperature is lower at lower loads for power plants. Therefore, EKPC either needs to document that stack exit temperature is the same at all loads with evidence from Spurlock 3 & 4 or other credible sources or EKPC needs to re-run this modeling using the correct exit temperature.

Division's Response to Comment III-I1:
The Division does not concur. The stack exit temperatures will be the same at all loads. Please see the Division's Response to Comment III-C1.

Comment III-J1:

J. ISSUES AFFECTING MULTIPLE POLLUTANTS
1. EMERGENCY GENERATOR AND FIREWATER PUMP
As explained elsewhere, the Smith Facility must have an emergency generator(s) and/or firewater pump(s). These are operated routinely to ensure availability. However, they are not included in any of the modeling. They must be.

Division's Response to Comment III-J1:
The Division does not concur. Please refer to the Division's Response to Comment I-A.

Comment III-J2:

2. THE MODELING GRID FOR CLASS II SOX, NOX, PM1O, & CO IS INACCURATE
In our initial comments, we noted that the modeling receptor grid (grid) was not adequate because it did not include land that is not fenced and that the public used for recreation. EKPC expanded the grid somewhat in response to our comment. However, this expansion was not adequate. Rather, there are at least three reasons why the grid should cover the whole area right up to the facility.

One is that the exclusion of areas on the applicants property form the grid is not specified in the language of the Clean Air Act or its state or federal regulations. Rather, it is based on a policy that ambient air should not include areas that members of the public are physically excluded from. That is a bad policy and it is time to change it. The policy effectively lets employers expose their workers to unhealthy levels of air pollution. Thus, the policy is inconsistent with the Clean Air Act and with common decency.

Another is that at least part of the area excluded from the grid are included in the proposed boundaries of the J.K. Smith Power Station Wildlife Management Area. We took a photograph of the Smith site with the proposed Wildlife Management Area boundaries drawn on it and imposed that on a map of the grid from the permit application. Ex. lll-j-2-1 is the result. The areas marked A and B on Exhibit lll-J-2-1 are areas inside the proposed Wildlife Management Area and yet still not part of the grid. The ambient air policy is that the public has to be permanently physically excluded. However, there is nothing stopping the proposed Wildlife Management Area from becoming an actual Wildlife Management Area after the CFBs begin to operate. Thus, areas A and B must be included in the grid. New modeling must be done with the new grid.

Finally, physical access is not limited along the entire length of the north side of Red River Road. Sara Pennington of KFTC traveled along Red River Road on February 10, 2010 and took photographs. Ex. lll-j-2-2 at para. 2-4. There are areas where the fence has gaps that appear to be specifically to allow people to walk through. Ex. lll-J-2-2 at para. 6. There are other areas where the fence is down or even areas, especially to the western end of Red River Road, where there is no fence. Ex. Ill-j-2-2 para. 5-6. Thus, the modeling needs to be re-run with a new, complete grid which the public is allowed to review and comment on before DAQ can make a final decision on the permit.

Division's Response to Comment III-J2:
The Division does not concur. For both the NAAQS and the PSD increment analyses, modeling receptors should be placed at ground level points anywhere except on the applicants plant property if it is inaccessible to the general public. Further, the Division agrees with EKPC’s February 25, 2010 response:

…"No Hunting" and "No Trespassing" signs are posted along the fence to the north of Red River Road along this property boundary. Gates in the fence along Red River Road are maintained with padlocks to prohibit public access. Accordingly, any person who accesses those lands is committing trespass under Kentucky law. KRS 511.090(4), Kentucky's criminal trespass statute, provides that a criminal trespass is committed when a person enters or remains upon unimproved and unused land that is fenced or "otherwise enclosed" or when notice is given by posting in a conspicuous manner. A civil claim for trespass in Kentucky can be maintained based solely on the intentional and unprivileged entry onto the land of another, a much lower standard than that required for a criminal trespass. The Smith station property is approximately 3,200 acres and includes approximately 3 miles of frontage along Red River Road. EKPC periodically conducts checks of the integrity of the fence along Red River Road and maintains the fences and gates to prohibit access to the property by trespassers. Accordingly, all Smith Station property located to the north of Red River Road is not ambient air, consistent with the revised modeling boundary.

Comment III-J3:

3. EKPC USED INADEQUATE METROLOGICAL DATA FOR AERMOD AND VISCREEN

The Jackson, Kentucky Airport data from 1990 through 1994 are not the preferred data for modeling air impacts from the proposed EKPC facility. These data are from 16 to 20 years ago, and were not collected with the updated instruments and quality assurance procedures currently in place at the Jackson Airport. The definition of preferred data is found in EPA's Guideline on Air Quality Models which DAQ is required to followed pursuant to 401 KAR 50:040 § 1. From Section 8.3.1.2 of the Guideline on Air Quality Models:

> *Five years of representative meteorological data should be used when estimating concentrations with an air quality model. Consecutive years from the most recent, readily available 5-year period are preferred. The meteorological data should be adequately representative, and may be site specific or from a nearby NWS station.*[24]

The Jackson Airport had ASOS (automated surface observing station) instrumentation installed and operating on December 1, 1995. ASOS represents the modernization of the National Weather Service airport meteorological data system. In addition to more robust instrumentation and quality assurance procedures, the ASOS wind sensors are typically installed at 10 meters above the ground (the standard wind instrument exposure height). The 1990 — 1994 Jackson wind speed and direction data were collected at only 6.1 meters (20 feet).

Jackson meteorological data through 2008 are readily available from the National Climatic Data Center (NCDC) and from numerous consulting firms that prepare AERMOD-ready meteorological data sets. While the data from NCDC and other entities may not be free, their cost is minor compared to the overall air quality modeling budget. It is important to note that the EPA Guideline on Air Quality Models does not define readily-available data to be that provided by regulatory agencies.

Meteorological data from 1990 - 1994 are not the most recent, readily- available five years of modeling data. Therefore they are not the preferred data for the EKPC project. Just as the EPA Guideline on Air Quality Models updates the preferred air dispersion models to reflect the current state-of- the-art, the preferred meteorological data must be updated to reflect current measurement and processing technology.

Therefore, EKPC must redo all of its modeling, both AERMOD and VISCREEN, with the preferred meteorological data or at the very minimum, with ASOS data. A new public comment period must be held to review this new modeling. Using ASOS meteorological data will establish that Smith causes or contributes to a violation of NAAQSs and increments.

Division's Response to Comment III-J3:
The Division does not concur. The use of the 1990-1994 meteorological data from the Jackson Airport was deemed acceptable for modeling EKPC emissions at the time of the application submittal, met the quality assurance and control requirements of the Division, and was readily-available to the public.   40 CFR Part 51, Appendix W, "Guideline on Air Quality Models", was followed for choosing appropriate meteorological data.

Comment III-J4:

4. EKPC USED THE 20D RULE TO IMPROPERLY EXCLUDE SOURCES
The AERMOD full impact modeling for NAAQS and PSD increment analyses has used the 20D screening method to omit numerous facilities from the SOx, NOx, and PM modeling. See Ex. I-1 at 1076. Developed in 1985 by North Carolina Department of Natural Resources, this screening method is strictly applicable to low-level sources with effective stack height of 10 m and located in flat terrain. See North Carolina DNR, 2985. Screening Threshold Method for PSD Modeling, letter dated July 22, 1985 from E. Haynes of NC DNR to L. Nagler, EPA Region 4.

EKPC omitted numerous facilities that do not meet the criteria from the 20D screening method. For example, EKU was excluded even though it has an effective stack height of well more than 10 m. Some of these omitted facilities can be PSD increment consumers and should not be omitted. All facilities that do not meet the 20D criteria, that is are not low level sources with effective stack heights of 10 m or are not located in flat terrain should be put back into the models for

SOx, NOx, and PM10 which should be rerun and then provided to the public for review during a new public comment period.

Division's Response to Comment III-J4:
The Division does not concur. The "Screening Threshold" method is conservative and takes into account that most sources have effective stack heights greater than 10 meters. In addition, there is no mention of flat terrain in the referenced document. Thus, the method was applied correctly and the determination that these facilities can be eliminated from the NAAQS and PSD increment analyses is acceptable.

Comment IV-A:

IV. THE DRAFT PERMIT FAILS TO REQUIRE BEST AVAILABLE CONTROL TECHNOLOGY LIMITS

A. THE DRAFT PERMIT FAILS TO IMPOSE BACT FOR GREENHOUSE GASES FOR THE CFBs

Greenhouse gas emissions are a class of pollutants entirely ignored by the DAQ and EKPC. Despite the nation's growing commitment to curbing greenhouse gas emissions that contribute to climate change, and pending federal regulation to do just that, neither the DAQ nor EKPC has even disclosed the quantity of greenhouse gases, including carbon dioxide ("C02") that the facility is expected to emit.[25] In the absence of such an analysis, using carbon mass-balance assumptions and relying on simplifying assumptions, Sierra Club estimates CO2 emissions of approximately 1 million tons per year, or 50 million tons of CO2 total if the plant operates for 50 years.[26] While this value is not exact, it is indicative of the rough order of magnitude of the considerable quantities of CO2 emissions that the CFBs will emit. In short, it is undeniable that the proposed plant will emit huge quantities of the pollutants causing a climate crisis.

The 1 million tons per year of carbon dioxide that the CFBs would emit far exceed the EPA's proposed major source threshold for greenhouse gases of 25,000 tons per year.[27] The DAQ must disclose the plant's potential GHG emissions and limit those emissions to what is achievable with the best available control technology ("BACT"). Such a limit is required by the Clean Air Act, as explained below. The public should have an opportunity to review and comment upon DAQ's analysis.

1. CLIMATE CHANGE BACKGROUND

It is now undisputed that global climate change poses serious risks to human health and the environment.[28] Warmer temperatures, more severe droughts and floods, and sea level rise, the results of climate change, will affect important economic resources such as agriculture, forestry, fisheries, and water resources. All these stresses can add to existing stresses on resources such as land-use *changes and pollution. The United States Environmental Protection Agency ("EPA") determined, based on a full review of the scientific evidence and focusing on impacts within the United States, that six greenhouse gases (including CC2) endanger both the public health and the public welfare.[29] In making this finding, EPA pointed to risks to human health associated with changes in air quality, increases in temperatures, changes in extreme weather events, increases in food- and water-borne pathogens, and changes in aeroallergens. As the EPA stated:*

> *The evidence points ineluctably to the conclusion that climate change is upon us as a result of greenhouse gas emissions, that climatic changes are already occurring that harm our health and welfare, and that the effects will only worsen over time in the absence of regulatory action. The effects of climate change on public health include sickness and death . . . . The effects on welfare embrace every category of effect described in the Clean Air Act's definition of "welfare" and, more broadly, virtually every facet of the living world around us. . . In both magnitude and probability, climate change is an enormous problem.[30]*

The effects of climate change include "heat waves, more wildfires, degraded air quality, more heavy downpours and flooding, increased drought, greater sea level rise, more intense storms, harm to water resources, harm to agriculture, and harm to wildlife and ecosystems."[31] The agency concluded that "[t]he evidence concerning adverse air quality impacts provides strong and clear support for an endangerment finding."[32]

EPA's recent pronouncement is based on well-established facts that the international scientific and regulatory community has known for over a decade. The Intergovernmental Panel on Climate Change ("IPCC") was established by the World Meteorological Organization and the United Nations Environment Programme in 1988 to comprehensively and objectively assess the scientific, technical, and socio-economic information relevant to human- induced climate change, its potential impacts, and options for adaptation and mitigation.[33]

The impacts of climate change on Kentucky are tangible and worrisome:

o Global warming could lead to a significant reduction in the abundance and habitat range of trout in the Appalachian region, including a 61 percent decrease in abundance and 90 percent loss of habitat for brook trout in headwater streams.

o Western Kentucky's Gulf Coastal Plain is home to some of the last bald cypress-tupelo swamps in the Mississippi Delta, which provide habitat for a variety of threatened and endangered species as well as wintering waterfowl. Global warming is expected to bring more invasive species, more flooding, more droughts and different migration patterns for species like the wood duck.

o Kentucky's timber industry could see a decline as valuable eastern hardwoods are replaced by scrub oaks and other trees that carry less commercial value but are better adapted to warmer temperatures.

o With more running water than any state but Alaska, many of Kentucky's ecosystems and economic activities dependent on reliable water resources. If global warming leads to drier conditions in the region, it could affect irrigation, urban water supplies and habitat for fish and wildlife.

o Loss of wildlife and habitat could mean a loss of tourism dollars. In 2006, more than 2.4 million people spent more than $1.8 billion on wildlife viewing, hunting and fishing, which in turn supported 41,765 jobs in Kentucky.[34]

Global warming also exacerbates the problem of ground-level ozone ("smog"), intensifying the public health dangers associated with air quality violations. Breathing ozone can trigger a variety of health problems, including chest pain, coughing, throat irritation, and congestion, and repeated exposure can lead to bronchitis, emphysema, asthma, and permanent scarring of lung tissue. In addition, global warming will result in increased surface water evaporation, which in turn could lead to more wildfires and increased dust from dry soil, both of which generate particulate matter emissions. Particulate matter triggers a host of health problems, including aggravated asthma, development of chronic bronchitis, irregular heartbeat, nonfatal heart attacks, and premature death in people with heart or lung disease.

New evidence suggests that even the alarming estimates of the dire threat of the pending global climate meltdown by the IPCC are too conservative and that the threat of global warming may prove even more imminent than originally anticipated. A recent study found that from 2000 to 2006, the average growth in GHG emissions was 3.3% per year, compared to 1.3% per year during the 1990s. The study estimates that the climate meltdown is happening faster than previously feared, and attributes this to recent growth in carbon intensity, and decreasing efficiency in carbon sinks on land and in oceans.

The certainty surrounding climate change has spurred national and state governments into action. Congress is actively considering regulating carbon emissions, with several bills offered last year. Based on this legislation, President Obama recently made a commitment to reduce greenhouse gas emissions in the range of 17 percent below 2005 levels by 2020 and 83 percent by 2050.[36] *The EPA is also on the verge of issuing regulations covering greenhouse gas emissions from automobiles.*[37] *Many states, such as Montana, Washington, Delaware, California and New jersey have also taken the initiative to limit greenhouse gases from industrial polluters.38 As the Director of the Kansas Department of Health and the Environment stated in denying a permit application for the proposed 1,400 MW Holcomb coal plant, "it would be irresponsible to* *ignore emerging information about the contribution of carbon dioxide and other greenhouse gases to climate change and the potential harm to our environment and health."*[39]

2. THE CLEAN AIR ACT REQUIRES A BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS FOR GREENHOUSE GAS EMISSIONS FROM THE CFBS

A PSD permit for a source that emits significant quantities of a pollutant "subject to regulation" under the Clean Air Act must include an emissions limit based on the best available control technology ("BACT") for that pollutant.[40] *There is no dispute that the Smith plant will emit CO2 and that these emissions will far exceed the EPA's proposed major source threshold for greenhouse gases of 25,000 tons/year.*[41] *As discussed below, CO2 is regulated under the Act. Therefore, the DAQ must require a BACT limit for these emissions.*[42]

Additionally, the EPA is on the verge of issuing regulations covering greenhouse gas emissions ("GHG") from automobiles. In September 2009, the EPA announced that it "expects soon to promulgate regulations under the Clean Air Act to control GHG emissions and, as a result, trigger PSD and Title V applicability requirements for GHG emissions."[43] *The result of U.S. EPA's rulemaking will have a direct impact on the Smith permit because EPA is expected to finalize the mobile source GHG rule in March 2010, which will likely occur before the DAQ finalizes a PSD/Title V permit for the Smith Facility. However, that final rulemaking is unnecessary for determining that CO2 and other GHGs are already subject to regulation under the Clean Air Act, as shown below.*

As the DAQ is aware, the Environmental Appeals Board ("EAB") has repeatedly rejected refusals by EPA and delegated states to apply BACT requirements to GHG emissions under the Clean Air Act as unsupported by any existing law or policy. In re Deseret Power Electric Coop., PSD Appeal No. 07-03, slip op. at 25 (Nov. 13, 2008) (attached as Exhibit IV.A.1); In re Northern Michigan University R4oIey Heating Plant, Slip. Op., PSD Appeal No. 08-02 (E.A.B. 2009) (attached as Exhibit IV.A.2). In Deseret, the EAB remanded the issue to the EPA Region to reconsider whether the agency should require CO2 BACT limits. In re Deseretat 63-64. The EAB remanded the permit in Northern Michigan for the same reasons as Deseret, and additionally instructed the Michigan Department of Environmental Quality to consider whether nitrous oxide (N20) is regulated under the Act. In re Northern Michigan at 31-32. The only legally defensible conclusion on remand is that CO2 is subject to regulation and, therefore, that BACT limits are required for CO2. The DAQ cannot ignore these clear directives from the EAB.

In light of all this, other project proponents have begun to submit CO2 BACT analyses.[45] *And other permitting authorities have issued draft permits with CO2*

BACT limits.[46] While these CO2 analyses suffer their own flaws, they do demonstrate that the regulated community and regulatory agencies have now concluded that CO2 BACT limits are a requirement of the Clean Air Act.

a. GREENHOUSE GASES ARE "AIR POLLUTANTS" UNDER THE CLEAN AIR ACT

The Clean Air Act defines "air pollutant" expansively to include "any physical, chemical, biological, radioactive . . . substance or matter which is emitted into or otherwise enters into the ambient air." 42 U.S.C. § 7602(g) (emphasis added). The U.S. Supreme court confirmed in Massachusetts v. EPA, 549 U.S. 497 (2007), that greenhouse gases fit within this expansive definition. The court held that it is "unambiguous" that the "sweeping definition" of air pollutant found in the Act "embraces all airborne compounds of any stripe," including CO2 and other greenhouse gases." Id. at 528-29. See also In Re Deseret Power Electric Coop., PSD Appeal No. 07-03, Slip Op. (EAB November 13, 2008).

b. CARBON DIOXIDE AND METHANE ARE CURRENTLY REGULATED UNDER THE CLEAN AIR ACT

Given the threat posed by global warming, it is now more important than ever to implement the federal clean Air Act's requirement to impose stringent BACT limits on GHG emissions from new coal plants. The PSD program requires that each "new major stationary source shall apply best available control technology for each regulated new source review pollutant that it would have the potential to emit in significant amounts." 40 C.F.R. § 52.21(j), 51.166(j)(2) (emphasis added). A "regulated new source review pollutant" includes any pollutant for which there is a national ambient air quality standard ("NAAQS"), a standard promulgated under Section 111 of the Act, and "any pollutant that otherwise is subject to regulation under the Act." 40 C.F.R. § 52.21(b)(50), 51.166(b)(49). The clean Air Act itself also makes clear that the BACT requirements extend to "each pollutant subject to regulation under the Act." 42 U.S.c. § 7475(a)(4), 7479(3).

Carbon dioxide and methane are regulated in numerous ways, both by regulations that require the monitoring and reporting of CO2 emissions and by regulations that limit the actual emissions of CO2 and methane.47 In addition, the EPA will regulate GHG emissions from automobiles before the smith permit is finalized.

c. CO2 IS ALSO REGULATED UNDER THE CLEAN AIR ACT THROUGH THE SPECIAL REGULATION OF AUTO EMISSIONS BY NUMEROUS STATE PURSUANT TO THE ACT'S CALIFORNIA CAR WAIVER

EPA authorized the state of California to implement its motor vehicle greenhouse gas emission standards, pursuant to Section 209(b) of the Clean Air Act, 42 U.S.C. § 7609(b), on June 30, 2009.48 As a result, CO2 was immediately subject *to emission limits not only in California, but also in 10 of the 14 other states that have imposed these same standards pursuant to their independent authority under Section 177 of the Clean Air Act, 42 U.S.C. § 7507. As a result, carbon dioxide and methane are now "subject to regulation" under the "California Car Waiver" provisions of the Clean Air Act.*

The EPA's approval of new motor vehicle standards unequivocally requires "actual control" of C02, nitrous oxide, and methane emissions:

> *California's greenhouse gas emissions standards establish allowable grams per mile (gpm) levels for greenhouse gas emissions, including tailpipe emissions of carbon dioxide (C02), nitrous oxide (N20), and methane (CH4), as well as emissions of CO2 and hydrofluorocarbons (HFC5) related to operation of the air conditioning system.*[49]

California's grams-per-mile standards (the "CO2 Emission Limits") are effective for model years 2009 through 2016:

[California's] regulation covers large-volume motor vehicle manufacturers beginning in the 2009 model year, and intermediate and small manufacturers beginning in the 2016 model year and controls greenhouse gas emissions from two categories of new motor vehicles — passenger cars and the lightest trucks (PC and LDT1) and heavier light-duty trucks and medium-duty passenger vehicles (LDT2 and MDPV).[50]

Because Model Year 2010 began on January 2, 2009 (and Model Year 2009 began on January 2, 2008[51]*), the "CO2 Emission Limits" are currently in effect and govern CO2, N20, and methane emissions from all new motor vehicle sales and registrations. Moreover, these limits are in effect in 10 states beyond California: Connecticut, Maine, Massachusetts, New Jersey, New York, Oregon, Pennsylvania, Rhode Island, Vermont, and Washington.*[52] *Each of these states adopted the CO2 and methane limits pursuant to Section 177 of the Clean Air Act, 42 U.S.C. § 7507. Section 177 expressly grants other states the authority to adopt California's vehicle emission standards:*

> *Section 177 of the Act contains an "opt-in" provision that allows any other state to "adopt and enforce for any model year standards relating to control of emissions from new motor vehicles" if "such standards are identical to the California standards for which a waiver has been granted for such model year" and are adopted "at least two years before commencement of such model year."*[53]

American Automobile Manufacturers Association v. Cahill, 152 F.3d 196, 198 (2d Cir. 1998). But for this provision of the Clean Air Act, states would not have been allowed to limit tailpipe emissions of CO2 and methane. In short, the auto *emission standards are regulations under the Clean Air Act. In fact, two federal courts have found that these very CO2 Emission Limits are indeed federal Clean Air Act standards. In Central Valley Chrysler-Jeep, Inc v. Goldstene, 529. F.Supp.2d 1151, 1165 (E.D. Cal. 2007), the court rejected the notion that even when approved under Section 209 of the Act, the CO2 Emission Limits are and remain state regulations and therefore subject to preemption by the federal Energy Policy and Conservation Act ("EPCA"): "The court can discern no legal basis for the proposition that an EPA- promulgated regulation or standard functions any differently than a California-promulgated and EPA-approved standard or regulation."[54] Faced with the identical argument, the court in Green Mountain Chrysler v. Crombie, 508 F.Supp.2d 295, 350 (D. Vt. 2007), also rejected the idea that the CO2 emission limits were not federal standards, concluding "that the preemption doctrine does not apply to the interplay between Section 209(b) of the CAA and EPCA, in essence a claim àf conflict between two federal regulatory schemes."*

Moreover, states have been exercising their Section 177 authority for almost two decades; the first to do so was New York, adopting California's original Low Emission Vehicle standards in 1992.[55] Not only have states adopted these emission standards under their Section 177 authority, but typically each state will then incorporate the more stringent auto emission standards into its SIP under Section 110 of the Act, 42 U.S.C. § 7410.[56] Once incorporated into a SIP, these requirements become CAA standards, and numerous provisions authorize both EPA and citizens to enforce such SIP requirements.[57,58]

d. THE DELAWARE SIP INCLUDES ACTUAL CONTROL OF CO2 AND IS INCLUDED IN SUBCHAPTER C

CO2 is subject to regulation under the Clean Air Act through EPA's approval of amendments adding various CO2 regulations to the State Implementation Plan ("SIP") for the State of Delaware.[59] Therefore, Section 52.420(c) of Part 40 limits emissions of CO2 in addition to establishing operating requirements, record keeping and reporting requirements, and CO2 emissions certification, compliance, and enforcement obligations for new and existing stationary electric generators.[60] EPA's approval was made "in accordance with the Clean Air Act," 73 Fed. Reg. 23,101, and included the rule in Part 52.

The approved Delaware SIP limits emissions of CO2 from certain electric generators to the following rates:[61]

	Delaware SIP Emission Limit
Existing Distributed Generators	*1,900 lbs/MWh*
New Distributed Generators	*1,900 lbs/MWh (if installed between effective date and 1/1/2012) 1,650 lbs/MWh*

	(if installed on or after 1/1/2012)
New Distributed Generators that use Waste, Landfill or Digester Gases	*1,900 lbs/MWh*

The regulated generators must certify compliance with these CO2 emission limits, monitor, and keep records.[62]

The Delaware Regulation 1144 is "under the Act." Delaware submitted Regulation 1144, including the CO2 emission limits contained therein, for EPA approval on November 1, 2007.[63] *EPA determined that the submission satisfied the requirements under CAA § 110(a), and published notice of its approval of the SIP revision in the Federal Register on March 5, 2008.*[64] *EPA allowed for public comment and, on April 29, 2008, EPA published notice of its Final Rule approving the SIP revision, effective May 29, 2008, in the Federal Register.*[65] *Both the proposed and final rule notices state that EPA's approval of Delaware's Regulation 1144 was "under" and "in accordance with the Clean Air Act."*[66]

e. ***CO2 AND METHANE ARE ALSO BOTH SUBJECT TO "ACTUAL CONTROL" AS*** *TWO* ***OF THE LANDFILL GASES LIMITED BY THE NEW SOURCE PERFORMANCE STANDARDS LOCATED IN SUBCHAPTER C***

EPA also promulgated emission standards for municipal solid waste ("MSW") landfill emissions in Subchapter C.[67] *"MSW landfill emissions" are defined as "gas generated by the decomposition of organic waste deposited in an MSW landfill or derived from the evolution of organic compounds in the waste."*[68] *EPA has specifically identified CO2 and methane as the two primary components of the regulated "MSW landfill emissions."*[69] *Thus, these pollutants are regulated through the landfill emission regulations at 40 CFR Part 60 Subparts Cc, WWW.*[70]

EPA explicitly intended to control greenhouse gases, including methane and carbon dioxide, through the NSPS for landfills. In a background technical document for the NSPS standard, EPA acknowledged that air emissions of greenhouse gases, including carbon dioxide and methane "contribut[ed] to the phenomenon of global warming," and that the "global warming effects" of those emissions posed "potential adverse health and welfare effects."[71] *In fact, any limit on landfill emissions necessarily limits carbon dioxide and methane because those two pollutants constitute nearly 100% of landfill gases—with other non-methane organic compounds constituting less than 1%. Therefore, EPA explained that one of the specific justifications for regulating landfill gases, and particularly for the level of stringency, was to limit emissions of methane to avoid global warming impacts.*[72] *EPA further noted in the rule's preamble to the final rule that* ***"[****c]arbon dioxide is also an important greenhouse gas contributing to climate change," and quantified the benefits of the rule based on "equivalent reduction in*

Co2.,, 56 Fed. Reg. 24,468, 24,472 (May 30, 1991) (stating that "1.1. to 2.0 billion trees would need to be planted ... to achieve an equivalent reduction in CO2 as achieved by today's proposal"). A rule limiting landfill gas emissions—consisting of 50% carbon dioxide and 50% methane— is clearly a rule limiting emissions of those two pollutants.

f. CO2 IS REGULATED THROUGH MONITORING AND REPORTING REQUIREMENTS

In section 821 of the 1990 Amendments to the Act, Congress made CO2 "subject to regulation" for purposes of the Act's Section 165 BACT provisions. Enforcement of Section 821 is accomplished through the enforcement mechanism in the Act, 42 U.S.C. § 7413(a)(4), (b)(2),7604(a)(1), and a violator is subject to the penalty provisions of the Act.[73] In 1993, EPA issued the regulations required by Section 821. 40 CFR Part 75. Those regulations generally require monitoring of carbon dioxide emissions through installation, certification, operation, and maintenance of a continuous emission monitoring system or an alternative method, 40 CFR § 75.1(b), 75.10(a)(3); preparation and maintenance of a monitoring plan, 40 CFR § 75.33; maintenance of certain records, 40 CFR § 75.57; and reporting of certain information to EPA, including electronic quarterly reports of carbon dioxide emissions data, 40 CFR § 75.60 - 64.

Additionally, 40 CFR § 75.5 prohibits operation of an affected source in the absence of compliance with the substantive requirements of Part 75, and provides that a violation of any requirement of Part 75 is a violation of the Clean Air Act. These regulations are located in Title 40, Chapter I, Subchapter C, which makes them "regulation[s] under the Act," according to EPA's only official interpretation.[74]

Furthermore, EPA has identified the CO2 monitoring and reporting requirements in Part 75 as applicable Clean Air Act requirements that must be incorporated into Title V operating permits. 40 CFR § 71. EPA has enforced CO2 monitoring regulations under the Clean Air Act on a number of occasions. It is, therefore, undeniable that CO2 is subject to regulation under the Clean Air Act.

g. BEFORE THE SMITH PERMIT IS FINALIZED, EPA WILL REGULATE GHG FROM AUTOMOBILES

In May 2009, EPA issued proposed rule to regulate GHGs from mobile sources under title II of the CAA. 74 Fed. Reg. 24,007 (May 22, 2009). EPA stated that it expects to finalize these final regulations in March 2010. 74 Fed. Req. at 55,295 ("the light-duty motor vehicle rule, which EPA recently proposed and expects to promulgate by the end of March 2010"), at 55,296 ("March 2010, when we expect PSD and title V requirements to be triggered for GHG emitters"). In addition, EPA has publicly announced that "it is EPA'S position that new pollutants become subject to PSD and title V when a rule controlling those *pollutants is promulgated (and even before that rule takes effect). Accordingly, as soon as GHGs become regulated under the light-duty motor vehicle rule, GHG emissions will be considered pollutants "subject to regulation" under the CM and will become subject to PSD and title V requirements." 74 Fed. Reg. at 55,300.*

Since the DAQ will not finalize the Smith PSD/Title V permit before EPA is expected to issue this light-duty motor vehicle rule, this new units will unquestionable need an enforceable BACT limit for its GHG emissions, including CO2. For these reasons, the DAQ must quantify and limit the CFBs' emissions of CO2 and methane and release a new draft permit for public review.[75]

3. THERE ARE NUMEROUS OPTIONS AVAILABLE TO AVOID OR MINIMIZE THE PROJECT'S GREENHOUSE GASES

Options exist to reduce the emission of GHGs from the CFBs, which include:

o Increased Efficiency (e.g., the proposed project is a subcritical CFB and there are supercritical CFBs commercially available);

o Co-firing or firing by itself the combustion sources proposed for the plant with lower carbon fuels, including biomass or natural gas, instead of coal-based fuels;

o Use of carbon capture and sequestration; and

o Controls options and work practice standards.

The first two options are discussed in detail below.

a. BACT FOR GHG IS IMPROVED EFFICIENCY THROUGH USE OF A SUPERCRCAL CFB

A power plant implementing BACT is designed for high efficiency not only for economical reasons but also for enhanced environmental performance in terms of reduced emissions and quantity of ash generated due to lower fuel consumption. Supercritical pressure steam cycles, in a supercritical CFB, offer higher efficiencies and lower emissions than subcritical pressure plants. EKPC should install supercritical CFB units because they are more efficient CFBs and are commercially available and proven operational.

EKPC's plan is to build the CFBs as subcritical units. Subcritical means the water in the boiler is at a subcritical stage. The majority of coal-fired power plants built in the United States in recent years have been supercritical units. All else being equal, supercritical coal-fired units are more efficient than subcritical coal-fired units. This means a supercritical unit has to purchase less fuel per unit of electricity generated, and is thus less expensive to operate, than an equivalent *subcritical unit. This also means that a supercritical unit emits less pollution, including greenhouse gas pollution, per unit of electricity generated, than a subcritical unit. All of the Smith facility's CFBs operate at below 38% efficiency and EKPC predicts this to continue into the foreseeable future. This, however, is not BACT.*

In July 2009, the world's first supercritical CFB steam generator began successful operation at the Lagisza power plant in Poland, operated by Poludniowy Koncern Energetyczny SA.[76] *The 460-megawatt plant replaces the 40-year old pulverized coal units at the facility. Foster Wheeler provided the turnkey boiler island, including engineering and design, erection, civil work, start-up, and commissioning.*[77] *The boiler incorporates a number of advanced design features and produces electricity at an efficiency level well above that of typical coal plants, such as compact solid separators, INTREX superheaters, and low-temperature flue gas heat recovery that captures valuable heat that would otherwise be lost.*[78] *It also employs Benson vertical- tube supercritical steam technology.*[79] *"Specifically, in relation to the older, de-commissioned boilers, the new [supercrital] CFB burns less fuel and produces significantly lower levels of carbon dioxide and other emissions for each megawatt generated."*[80] *The DAQ should require EKPC to consider this improved efficiency technology for its BACT-down analysis of controlling CO2 emissions.*

A BACT limit based on use of supercritical CFB would not impermissibly "redefine" the source. The "source" within the "redefining the source" refers to the fundamental design, or "basic design," of the facility, not to the totality of the applicant's preferred design, facilities, and operation practices. In re Prairie State Generating Station, 13 E.A.D. —, PSD Appeal No. 05-05, Slip Op. at 27 (EAB Aug. 24, 2006) (citing Knauf Fiber Glass, 8 E.A.D. at 136; NSR Manual at B.13). This derives from the statutory language requiring that the "proposed facility" be subject to BACT. 42 U.S.C. § 7475(a)(4). In the context of the statute, the "proposed facility," refers to the "major emitting facility on which construction is commenced." 42 U.S.C. § 7475(a) ("No major emitting facility on which construction is commenced . . . may be constructed . . . unless . . . (4) the proposed facility is subject to the best available control technology). The Act defines the "major emitting facility" by facility type and, sometimes, by size. See 42 U.S.C. § 7479(1). Similarly, EPA defines the "major emitting facility" by Standard Industrial code category. 45 Fed. Reg. 52,676, 52,694 (Aug. 7, 1980).

In In re Prairie State Generating Station, 13 E.A.D. —' PSD Appeal No. 05-05, Slip Op. at 27 (EAB Aug. 24, 2006), the Environmental Appeals Board articulated the proper test to determine when consideration of a new technology is "redefining the source." As the Board explained, the permit applicant initially "defines the proposed facility's end, object, aim, or purpose — that is the facility's basic design," although the applicant's definition must be "for reasons independent of air permitting." Prairie State, slip op. at 29, 30 n.23, 13 E.A.D. at _; In re Northern Michigan University Ripley Heating Plant Slip. Op. at 26 &

n.28, PSD Appeal No. 08-02 (E.A.B. 2009) (attached as Exhibit IV.A.2). The inquiry, however, does not end there. The permit issuer (here, the DAQ) should take a "hard look" at the applicant's determination in order to discern which design elements are inherent for the applicant's purpose and which design elements "may be changed to achieve pollutant emissions reductions without disrupting the applicant's basic business purpose for the proposed facility," while keeping in mind that BACT, in most cases, should not be applied to regulate the applicant's purpose or objective for the proposed facility. Prairie State, slip op. at 30, 33-34, 13 E.A.D. at _; accord Northern Michigan University, slip op. at 26-27 (attached as Exhibit IV.A.2).

A supercritical CFB is in keeping with EKPC's goal, object, aim or purpose for this proposed facility. In its application, EKPC stated that its purpose was to construct "two new utility boilers" that "will serve as baseload generating units to meet current and future power demands throughout the transmission area." EKPC, Application Resubmittal at p. 1-1 (April 2008). The application goes on to state that "EKPC is proposing to build two nominal 278 MW (net) electric generating units: CFB1 and CFB2 EKPC is designing the proposed two new CFB boilers to fire run of [sic] mine bituminous coal and coal waste." Id. at 2-1. The implementation of a supercritical CFB is perfectly aligned with the applicant's "object, aim, or purpose — that is the facility's basic design." Moreover, the DAQ should consider the use of supercritical CFB technology because it will "achieve pollutant emissions reductions without disrupting the applicant's basic business purpose for the proposed facility."

In other words, the DAQ must consider plant design changes necessary to increase efficiency, as well as changes to the applicant's technology preference so that Congress' command to base emission limits on BACT is given effect. See, e.g., Knaut 8 E.A.D. at 140 (holding that an applicant cannot "circumvent the purpose of BACT, which is to promote the use of the best control technologies as widely as possible" by limiting review to the proprietary plant process and design that the applicant wished to construct); In Re: Desert Rock Energy Company, 2009 WL 3126170, — E.A.D. —, PSD Appeal Nos. 08-03, 08-04, 08-05, 08-06 (Sept. 24, 2009) (the Board remanded the permit for failure to consider IGCC in its BACT analysis; the court specifically held that consideration of IGCC was not redefining the source).

b. BACT FOR GHG IS THE USE OF BIOFUELS

Although CFB boiler can burn a variety of fuels, EKPC intends to burn bituminous coal and coal waste as the fuel. The one purported benefit of CFB boilers, as a category, is the ability to burn many gaseous fuels, almost any solid fuel, and to allow operation on renewable resources (such as switchgrass) up to 100% of the total heat input.

Because the use of biomass would result in the lowest emission rates of CO2, the use of 100% biomass as fuel (or a smaller percentage if that is all that is available) is the "top" pollution control option. This top control option is not infeasible, NSR Manual at B.?, nor are energy, environmental or economic impacts sufficient to justify rejecting it from the top-down BACT analysis. NSR Manual at B.8-B.9. The DAQ must establish the GHG limit based on biomass, rather than coal or coal waste is this is the appropriate feedstock for a BACT limit.

The applicable law requires that BACT limits be established based on the maximum degree of pollution reduction achievable with a number of specified methods, one of which is the use of clean fuels. 42 U.S.C. § 7479(3) (BACT includes "available methods, systems, and techniques, including clean fuels, fuel cleaning or treatment or innovative fuel combination techniques for control of the air contaminant." (emphasis added)); 40 C.F.R. § 52.21(b)(12) (same). Congress specifically intended that BACT limits be established by considering the maximum pollution reduction through using cleaner fuel. Inter-Power of New York, 5 E.A.D. at 134 (emphasis added, internal citations omitted); Knaut 8 E.A.D. at 136; In re Old Dominion Electric Cooperative. 3 E.A.D. 779, 794 n.39 (EAB 1992) ("BACT analysis should include consideration of cleaner forms of the fuel proposed by the source."). The EPA has also historically required consideration of clean fuel in establishing BACT limits. Id. For example, in Hibbing Taconite, the Administrator held that BACT must be determined based on the continued use of clean natural gas, rather than petroleum coke—a dirtier fuel. In re Hibbing Taconite Cc., 2 E.A.D. 838, 842-43, PSD Appeal No. 87-3, Slip Op. 9 (EAB 1989).

In its BACT analysis for GHG, EKPC and the DAQ must consider the use of biofuels, such as switchgrass, to fire the CFB units. If the CFB5 utilized 100% biomass or a combination of coal and biomass for its feedstock, CO2 emissions would significantly decrease. While the best global warming reducer would be a 100 percent biomass boiler, a combination of coal and biomass would still provide significant GHG reductions if there is not enough biomass to supply 100 percent of the boilers demand.[81]

In 2009, East Kentucky Power Cooperative and the University of Kentucky announced that it had demonstrated switchgrass' feasibility as an alternative energy form as it was combined with coal to generate electricity at East Kentucky Power's Spurlock Station in Maysville.°2 The switchgrass was mixed with the coal feedstock, replacing 1 to 2 percent of the coal normally used. EKPC announced that it is continuing to study switchgrass' energy potentials, and could possibly increase the percentage of switchgrass used to 3 to 10 percent. EKPC also told the KY Public Service Commission that it could burn a much greater percentage of switchqrass in its CFBs. See Ex. IV.A.4.

Co-firing Kentucky power plants with biomass was happily received by state politicians. In fact, Senator Charlie Borders, R-Russell, is hopeful that use of switchgrass could give some relief to Kentucky's coal industry, which might face stringent federal regulations on carbon emissions in the near future.[83] Moreover, the use of switchgrass, a native Kentucky grass, could mean extra money for farmers as well as reduced emissions from coal-fired power plants in the Commonwealth.[84]

EKPC is not the only utility to demonstrate that biomass can fuel power plants.

> *o The Department of Energy noted that in 2002 there were about 9,733 megawatts of installed biomass capacity in the United States.85 The sources of biomass included forest products and agricultural residues and were fired using gasification, direct firing, or co-firing.*
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> *o Michigan Technological University presented a report, commissioned by Wolverine Power Cooperative, which demonstrated the potential for homegrown biomass to reduce the use of fossil fuel while also decreasing carbon dioxide emissions from the generation of electricity.86 Wolverine Power Cooperative found that unused local logging residues could be used to generate at least 35 megawatts of electricity and that growing switchgrass could increase this biomass generation.87 Moreover, Michigan Tech found that using up to 20 percent biomass from logging residues offered the greatest potential CO2 and energy consumption reduction compared to geologic sequestration or reducing CO2 emission through forest stand management.[88]*
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> *o In April 2009, FirstEnergy Corporation announced that it plans to convert two units at its R.E. Burger Plant in Shadyside, Ohio, to generate electricity using biomass.[89] When the retrofit is complete, the plant is expected to be one of the largest biomass facilities in the United States. Once the project is completed, units 4 and 5 at the burger plant could be capable of producing up to 312 megawatts (MW) of electricity, which is its current capacity.*
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> *o On November 25, 2009, American Municipal Power Inc. announced plans for the likely conversion of the American Municipal Power Generating Station (AMPGS) project currently under development in Meigs County, Ohio. American Municipal Power Inc. stated that it would explore developing the project as a natural gas combined cycle facility supplemented with market purchases and pursue future enhancements for the project, such as biomass or another advanced energy technology.[90]*

o In February 2000, a report was issued documenting how the Lahti co-firing project at a pulverized coal and natural gas-fired district heating and electric generation plant in Finland uses a CFB gasifier to convert wood wastes and refuse derived fuel to low-Btu gas that is burned in the boiler. The operation has been technically successful for 1 year, and gives utilities in the United States another option to consider when examining the feasibility of co4iring biomass and waste fuels in coal-fired boilers.[91]

o In northern European countries, such as Sweden or Denmark, pellets are also used to fire biomass district heating or combined heat and power (CHP) plants. A growing market is also co-firing, whereby pellets are used to partially substitute coal in large power plants — for example in Belgium, the Netherlands and the U K.[92]

o Alabama Power Company is co-firing the Gadsden Electric Generating Plant with coal and biomass. The ultimate goal is for the facility to rely on biomass for 10 percent of its 140 megawatts of generating capacity.[93]

In October 2009, the San joaquin Air Pollution Control District issued a notice of preliminary determination for compliance for the construction of a 53.5 megawatt solar and biomass facility.[94]

In its consideration of biomass, EKPC and the DAQ need to consider cofiring with biomass in any percentage from 1 to 100. For instance, when Wolverine Electric Cooperative considered firing its CFB unit with biomass it found that even though a "significant biomass supply market does not presently exist in the vicinity of the site" that even the "6% of the heat input of a 600 [megawatt] plant" from wood pellets was "economically attractive." In addition, as discussed above, many of the facilities that use biomass only use it for a small percentage of their feedstock. Therefore, EKPC must assess what is the available supply of switchgrass, or other biomass feedstock, and consider co-firing with whatever supply is available.

Co-firing with biomass will help achieve President Obama's announced GHG reduction goals. For instance, if the United States commits to reducing its greenhouse gas emissions to 1990 levels by 2020 and by 80 percent in 2050, using more energy efficient technology and co-firing with biomass can help achieve that goal. If all the existing coal-fired power plants are replaced by new ultra-supercritical plants, you would reduce both coal use and greenhouse gases by 30 percent.96 If these units were further co-fired with 15 percent biomass, a total reduction to 45 percent could be achieved.[97]

Finally, a BACT limit based on use of biomass would not impermissibly "redefine" the source. Consistent with the statutory definition of BACT, *longstanding practice, and the recent EAB ruling in the Northern Michigan case, a top-down BACT determination must include consideration of "clean fuels." See 42 U.S.C. § 7479(3); In re Northern Michigan University RioIey Heating Plant, Slip. Op., PSD Appeal No. 08-02 (E.A.B. 2009) (attached as Exhibit IV.A.2). "Congressional direction to permitting applicants and public officials is emphatic. In making determinations, they are to give prominent consideration to fuels." Id. at 17-18. For a power plant this may include the use of natural gas or biomass in place of some or all of the coal stock, or a combination of any of these, as readily available methods to reduce carbon dioxide emissions.*

With a few exceptions, prior decisions by EPA correspondingly require consideration of clean fuels when clean fuels would not redefine the source from one category of "major emitting facility" to another. In Hibbing, the Administrator rejected application of the "redefining" policy, holding:

> *[O]ne argument that could be made is that the Region, by requiring the burning of natural gas to be an alternative to be considered in the BACT analysis, is seeking to "redefine the source." Traditionally, EPA has not required a PSD applicant to redefine the fundamental scope of its project. However, this argument has not been made, and in any event, the argument has no merit in this case. EPA regulations define major stationary sources by their product or purpose (e.g., "steel mill," "municipal incinerator," "taconite ore processing plant." etc.), not by fuel choice. Here, Hibbing will continue to manufacture the same product (i.e., taconite pellets) regardless of whether it burns natural gas or petroleum coke. Likewise, the PSD guidelines state that in choosing alternatives to be considered in a BACT analysis, the applicant must look to what types of pollution controls other facilities in the industry are using. The record here indicates that there are other taconite plants that burn natural gas, or a combination of natural gas and other fuels. Thus, it is reasonable for Hibbing to consider natural gas as an alternative in its BACT analysis. Moreover, because Hibbing is already equipped to burn natural gas, this alternative would not require a fundamental change to the facility.*

One narrow exception for the consideration of clean fuels occurred in Prairie State, in which the Board accepted Illinois' conclusion that the power plant in that case was intended and designed to burn a dedicated fuel supply, sufficient for the life of the plant, that is delivered directly from an adjacent mine. Sierra Club V. E.P.A., 499 F.3d 653, 655 (7th Cir. 2007) ("to convert the design from that of a mine-mouth plant to one that burned coal obtained from a distance would require that the plant undergo significant modifications-concretely, the half-mile long conveyor belt, and its interface with the mine and the plant, would be *superfluous and instead there would have to be a rail spur and facilities for unloading coal from rail cars and feeding it into the plant").*

However, it is apparent from the Prairie State case, the "redefining" policy is narrow. In Prairie State, the state agency considered pollution control options that would have required fundamental changed in design from a traditional coal power plant to a gasification and combined cycle plant. Prairie State, Slip. Op. at 36. As the Board noted, the fact that the state agency looked beyond the applicant's preferences to other types of power plants indicates that the "redefining the source" policy is not so narrow as to cut off consideration of pollution control options that would necessitate significant changes from the applicant's preferred strategy. Id.

The Prairie State case was therefore a narrow exception, based on the state agency's specific finding that the plant in that case was a specific type: a mine-mouth plant intended to burn a specified coal deposit. See Brief of EPA, In re Prairie State Generating Station, PSD Appeal No. 05-05 at 7 ("Prairie State applied for a permit to construct a single source that combines a coal mine and a coal fired-steam-electric-generating facility. ..Under these circumstances, requiring Prairie State to fire low-sulfur coal would fundamentally redefine the proposed project. Instead of constructing a mine on this site to supply coal, Prairie State would have to obtain low sulfur coal from another site and transport this coal to the facility, significantly altering the design, scope, and purpose of the project."). The Seventh Circuit specifically warned that the Prairie State decision should not be read as broadly allowing the "redefining" policy to trump the "clean fuels" provision in the Act, merely because some changes may be necessary to the plant in order to burn cleaner fuel.

> *"Suppose this were not to be a mine-mouth plant but Prairie State had a contract to buy high-sulfur coal from a remote mine yet could burn low-sulfur coal as the fuel source instead. <u>Some adjustment in the design of the plant would be necessary in order to change the fuel source from high-sulfur to low-sulfur coal . . . but if it were no more than would be necessary whenever a plant switched from a dirtier to a cleaner fuel the change would be the adoption of a "control technology." Otherwise "clean fuels" would be read out of the definition of such technology.</u>*
>
> *[Some passages in the Board's Prairie State decision] might be read as merging two separate issues: the difference between low-sulfur (clean) and high-sulfur (dirty) coal as a fuel source for a power plant, and the difference between a plant co-located with a coal mine and a plant that obtains its coal from afar. The former is a difference in control technology, the latter a difference in design (or so the EPA can conclude). We think it is sufficiently clear. . . that the Board did not confuse the two issues; that it granted the*

permit not because it thinks that burning low-sulfur coal would require the redesign of Prairie State's plant (it would not), but because receiving coal from a distant mine would require Prairie State to reconfigure the plant as one that is not co-located with a mine, and this reconfiguration would constitute a redesign."

Sierra Club, 499 F.3d at 656 (emphasis added in first paragraph, original in second paragraph). In other words, plant design changes necessary to burn cleaner fuel, as well as changes to the applicant's preferences or expectations must be considered so that Congress' command to based BACT limits on clean fuels is given effect.

In this case, use of biomass, such as switchgrass, instead of coal for a feedstock is not a change that would redefine the plant. Therefore, the DAQ should require its consideration in its GHG BACT analysis.

Division's Response to Comment IV-A:
The Division does not concur. KRS 224.10-100(26), as incorporated into Kentucky's State Implementation Plan (SIP), requires the state to implement its PSD program in a manner that is no more stringent than the federal PSD program. Currently, there are no federal regulations establishing PSD requirements for CO_2 (or any other greenhouse gas) at stationary sources. Specifically, the Division notes that the "Light-duty motor vehicle rule" cited in the comment is not effective.

Contrary to the comment above, there is no case law or EAB decision that has determined that CO_2 (or any other greenhouse gas) is "subject to regulation" under the Clean Air Act. Therefore, there is no requirement for EKPC to perform a BACT analysis for CO_2 (or any other greenhouse gas). Similarly, there is no requirement for the permit to include a CO_2 BACT limit. DAQ is not aware of any federal PSD permit that includes a CO_2 BACT analysis or limit. In November 2008, the EAB found that there was no established standard regarding whether CO_2 was subject to regulation under the federal PSD program. See *In re: Desert Power Electric Cooperative*, 14 E.A.D. ___, PSD Appeal No. 07-03 (November, 2008).

On December 31, 2008, U.S. EPA issued a Memo which established an interpretation of "subject to regulation" within the federal PSD regulation that "exclude[d] pollutants for which U.S. EPA regulations only require monitoring or reporting but [ ] include[d] each pollutant subject to either a provision in the Clean Air Act or regulation adopted by U.S. EPA under the Clean Air Act that requires actual control of emissions of that pollutant." Johnson Memo at 1; 73 Fed. Reg. at 80301. U.S. EPA received petitions to reconsider the position taken in the Memo. U.S. EPA continues to adhere to the interpretation reflected in Administrator Johnson's Memorandum of December 18, 2009. 75 Fed. Reg.17004 (April 2, 2010). Although, U.S. EPA Memorandums and EAB decisions are not binding on Kentucky's PSD program, these particular policies and decisions are relevant to the CO_2 comment above.

In light of the fact that there is no federal regulation establishing PSD requirements for CO_2 at stationary sources, KRS 224.10-100(26) requires that DAQ be no more stringent than the federal

PSD program. Similarly, whether other states, such as Delaware or California, voluntarily regulate CO_2 and choose to be more stringent than the federal PSD program, is not binding on Kentucky's PSD program.

The Division does not concur that GHG emission are subject to regulation pursuant to 40 CFR Subpart CC or Subpart WWW. Both regulations clearly state that the regulated pollutant is non methane organic hydrocarbons.

Given that neither a BACT analysis nor an emission limitation is appropriate for CO_2 (or any other greenhouse gas), no further public review or comment is necessary.

<u>Comment IV-B1:</u>

> *B. THE NOx BACT LIMIT AND ANALYSIS IS INADEQUATE*
> *1. EKPC AND DAQ FAILED TO CONSIDER A SUPERCRITICAL CFB, IGGC, SUPERCRITICAL PC, AND ULTRASUPERCRITICAL PC TO ACHIEVE NOx BACT*
>
> *The SOB only mentions 5 technologies in its NOx BACT analysis for the CFBs. SOB at 18. However, a BACT analysis requires the identification of all control technology. SOB at 17. This includes production processes or available methods, systems and techniques, including fuel cleaning or treatment of innovative fuel combustion techniques for control of the pollutant. Supercritical PC units in the 300 MW range exist and thus are technically feasible. See Ex. IV-B-].-1 at 4. As discussed elsewhere, supercritical CFB5 are also commercially available as are ultra-supercritical PCs. IGCCs are also commercially available. For example, Duke is currently building one in Edwardsport, Indiana and DAQ is permitting Cash Creek. Supercritical and Ultra-Supercritical PCs, as well as IGCC5 can achieve NOx emission rates that are approximately have of the Smith limit on a lb/MMBtu basis and even less on a lb/MWH basis. DAQ must consider these in a revised BACT analysis.*

<u>Division's Response to Comment IV-B1:</u>
The Division does not concur. The permit applicant defines the proposed facility's purpose and design, not the Division. BACT should not be applied to regulate the applicant's choice in design. Therefore, DAQ must discern which design elements are inherent to the proposed facility's purpose and design and which design elements could be altered to achieve emission reductions without disrupting the applicant's basic business purpose for the proposed facility.

IGCCs, Supercritical PCs (including ultra-Supercritical) and Supercritical CFBs would result in redefinition of the basic design project and is not required in a BACT analysis.

Integrated Gasification Combined Cycle (IGCC) is a fundamentally different process and design than a circulating fluidized bed (CFB) boiler. In CFB boilers, the fuel is coal, which is combusted. In IGCC, the coal is not the fuel. It is a chemical feedstock used in a series of chemical reactions called gasification. In gasification, the coal is not combusted, but is thermally converted in a series of chemical reactions, to create a synthetic gas, or syngas, which is the fuel for a separate combustion turbine power plant. An IGCC plant is more similar to a chemical plant, and has little in common with the combustion, steam generation and air pollution control (APC) systems utilized in CFB boilers.

Where CFB boilers are based on the Rankine thermodynamic cycle (steam production and use in a steam turbine), IGCC uses the Brayton cycle, based on firing a fuel, syngas, in a rotating combustion turbine. These two thermodynamic cycles are completely different. The gasification portion of an IGCC plant for use in coal-based power generation combines a chemical feedstock, coal, with steam and oxygen or air at high temperature and pressure to produce a gaseous mixture consisting primarily of hydrogen and carbon monoxide. This gaseous mixture, called syngas, is the result of a thermal conversion process, and not combustion. Where CFB boilers use excess air to assure combustion, gasification occurs in an "oxygen-starved" environment, in order to assure that combustion is precluded. Where the product of combustion in a CFB is hot flue gas that, after transferring its heat to boiler tubes, has no further use and must be exhausted through a stack, the product of gasification is a usable syngas, the intermediate step in providing a fuel for power generation in a combustion turbine, or for the production of chemicals. The syngas requires cooling and cleanup to remove contaminants to produce a synthesis gas (syngas) suitable for use in the combustion turbine portion of a combined cycle unit.

Coal gasification takes place in the presence of a controlled "shortage" of air/oxygen, thus producing reducing conditions, whereas combustion of coal in a CFB creates an oxidizing environment. It is important to note here that in gasification it is not the coal that is cleaned. Rather, it is the syngas, the product of gasification reactions, which is cleaned so that it can be used as a fuel in a separate process.

The Pulverized Coal (PC) process is based on the concept that if the coal is made fine enough, it will burn almost as easily and efficiently as a gas. Crushed coal from the silos is fed into the pulverizers along with air preheated to about 580°F. The hot air dries the fine coal powder and conveys it to the burners in the boiler. It is important that as much moisture as possible be removed from the coal, so that it can flow freely and not become sticky, as that would cause plugging. The burners mix the powdered coal in the air suspension with additional pre-heated combustion air and force it out of nozzles similar in action to fuel being atomized by fuel injectors. Combustion takes place at temperatures from 2,400-3,100 deg F, depending largely on coal rank (i.e., lignite, subbituminous, bituminous, anthracite).

The CFB fuel delivery system is similar to that of a PC unit, but somewhat simplified to combust a coarser material which is more difficult to burn completely. CFB combustion temperatures of 1,500 to 1,600°F are significantly lower than a PC boiler, which results in lower NOx emissions and reduction of slagging and fouling concerns that are characteristic of PC units. In contrast to a PC unit, SO_2 can be partially removed during the combustion process by adding limestone to the fluidized bed. This is because the reaction of sulfur dioxide (SO_2) with limestone (calcium carbonate) peaks at about 1,500 deg F, which is in the range of CFB boiler combustion. One of the main advantages of CFBs is that they have the ability to efficiently combust a wide range of low quality fuels. CFBs are often recommended for low grade, high ash coals which are difficult to pulverize, and which may have variable combustion characteristics.

PC and CFB can operate in either subcritical or supercritical mode. These terms refer to when steam is heated to above its critical point it can no longer exist as water. Thermodynamics are such that the higher the temperature is of a working fluid like steam, the more efficiency or energy can be extracted. Supercritical units use less fuel for the same amount of electricity produced, although there are serious technical and economic considerations involved in constructing supercritical units. To modify the CFB from subcritical to supercritical would require the redesign of the project. Boiler tubing, the boiler, pumps, and related piping would have to be redesigned to ensure proper operation and safety. This specific permit application proposes the phased construction of two independent CFBs. A 600 MW supercritical unit could not be built in phases as the two proposed 300 MW CFBs. To require the construction of one 600 MW supercritical unit would redefine the project.

Therefore, the fundamental differences in equipment design are sufficient to conclude that process in IGCC, PCs, Supercritical (including ultra-Supercritical) PCs and Supercritical CFBs would redefine the proposed source.

Best Available Control Technology (BACT) analysis involves identifying all potentially applicable emission control options. However, it does not require the applicant to redefine the design of the source. Redefining the design of the source relates to meeting the purpose and need for the project, and/ or in changing the fundamental constituents of the project's design. The BACT process is set up to identify the emission control technologies available to reduce emissions from the source as defined by the applicant. The BACT process, coupled with PSD increment and ambient air quality modeling, will ensure that emissions from the proposed facility will be minimized and that the proposed facility will not cause or contribute to any violation of an ambient air quality standard.

As noted in Desert Rock, the term "'innovative fuel combustion techniques' may place an outer limit on the 'redefining the source' policy…, but the EPA has not established as a matter of federal law that IGCC technology must be considered in BACT analysis in all circumstances." Desert Rock, slip. Op. at 77 n. 82.

<u>Comment IV-B2:</u>

> *2. HIGH TEMPERATURE, "HIGH" DUST SCR IS TECHNICALLY FEASIBLE AND COST EFFECTIVE*
>
> *The SOB dismissing high temperature, "high dust" SCRs on coal fired CFBs out of hand without any reference to supporting documentation. We put "high dust" in quotes because although a high temperature, high dust SCR would be upstream of the baghouse, it would be downstream of another control device such as U-beams or a multi-cyclone.*
>
> *Other agencies have permitted SCRs on coal fired CFBs. See Ex. IV-B-2-1.*[98] *Multiple vendors will guarantee an SCR on a coal-fired CFB. See Ex. IV-B 2-2 para. 2-4. In fact, EKPC itself has successfully pilot tested an SCR on its coal fired CFB and is now planning on building one. See Ex. IV-B-2-2, para. 4. We do*

not know if the EKPC pilot test and the planned SCR are hot side, cold side or tail end but EKPC must. To the extent that DAQ does not know, it should require EKPC to provide it with complete information and then hold a new public comment period for the public and EPA to review this information and comment on it.

Technically feasible control options are those that have been demonstrated in practice... If the technology is undemonstrated, then the applicant must evaluate whether it is "available" and "applicable" to the proposed facility. The NSR Workshop Manual provides explanation for what "available" and "applicable" mean in the context of Step 2 of a Top-Down BACT analysis. "A control technique is considered available, within the context presented above, if it has reached the licensing and commercial sales stage of development." P49 at B.18.[99] "In general, a commercially available control option will be presumed applicable if it has been or is soon to be deployed (e.g., is specified in a permit) on the same or a similar source type. Absent a showing of this type, technical feasibility would be based on examination of the physical and chemical characteristics of the pollutant bearing gas stream and comparison to the gas stream characteristics of the source types to which the technology had been applied previously. Deployment of the control technology on an existing source with similar gas stream characteristics is generally sufficient basis for concluding technical feasibility barring a demonstration to the contrary." Id. 120. The lack of a vendor guaranteed emission rate for a control technology does not mean that it does not represent the maximum achievable reduction for the application. The NSR Workshop Manual says as much on page B.20 in P49. According to jt. 39a, EKPC did not have guarantees for its PM and SOx emission limits in its permit for Spurlock 4. This indicates that EKPC can proceed with a BACT limit for which it does not have a guarantee.

BACT is the most effective, technically feasible option that was not rejected based on cost, energy or environmental reasons. The NSR Manual lists the following sources for inclusion in a BACT analysis:

1) EPA's BACT/LAER Clearinghouse (a database maintained by EPA containing a list of limits imposed on permit units);
2) BACT guidelines and determinations made by the South Coast Air Quality Management district or SCAQMD;
3) control technology vendors;
4) federal, state, local new sources review permits and associated inspection/ performance tests;
5) environmental consultants;
6) technical journals, reports and newsletters (e.g. the Mcllvaine Newsletters42 and the referee journals, like the Journal of the Air Pollution Control Association), air pollution control seminars; and 7) EPA's New Source Review bulletin board. Also mentioned are technologies in application outside the U.S. if they have been successfully demonstrated in practice on full scale operations.

P49 at B.11.

EKPC submitted several BACT analyses for Spurlock 4 but the final, complete BACT analysis is in Joint Exhibit 31. That is, while some additional information was submitted after Joint Exhibit 31 to supplement Joint Exhibit 31, Joint Exhibit 31 was the last complete BACT analysis EKPC submitted. 12/11 Tr. 43:9 — 44:9.

According to DAQ, there were difficulties with the permit application. Specifically, "it didn't contain a satisfactory BACT analysis and there wasn't time to resolve the issues in the normal back-and-forth process between the Division and the applicant." Newell Cab. W.D. 13:13-15.

DAQ and EKPC have agreed that SCR is a potentially applicable control technology for a coal-fired CFB under Step 1 of a NOx BACT analysis. See e.g. Jt. 31 atJoint3l.0016 —Joint3l.0017. However, it is important to discuss the particular configuration of SCR when discussing the technical feasibility or cost of an 5CR. A description of these configurations follows.

"Dust" is another terms used for particulate matter. So, "high dust" means that the SCR is placed in a position before the flue gas has passed through a high efficiency particulate control device such as an electrostatic precipitator or a baghouse. Low dust, on the other hand, means the SCR is placed in a position after the flue gas has passed through a high efficiency particulate control device.

Hot-side means the SCR is placed in a position before the flue gas has passed through the air heater, which is also typically called the air preheater. Cold-side means the SCR is placed in a position after the flue gas has passed through the air preheater, the high efficiency particulate control system, and the SO_2 scrubber so the flue gas is much cooler. The air preheater is a large heat exchanger that takes heat out of the flue gas leaving the boiler and "recycles" that heat into the air injected into the boiler. All large coal-fired boilers, be they PCs or CFBs, have air preheaters.

P100, page 9, lists these SCR configurations. The top diagram on page 10 is a hot-side, high dust SCR placement. The flue gas comes out of the boiler, which is labeled "steam generator" on the left side of the diagram, and travels through the SCR and after leaving the SCR the flue gas goes through the air preheater and then the particulate control device which in this case is an electrostatic precipitator. Page 11 has a diagram of a hot-side, low dust SCR. The flue gas comes out of the boiler, again on the left side, then travels, as represented by the red line, through an ESP before it enters the SCR. Thus, the particulate matter concentration, or "dust" concentration, has been reduced by the ESP before the flue gas runs through the SCR. However, the flue gas has still not passed through the air preheater, which is not shown on page 11.

A tail-end configuration is shown on page 12. In this diagram, again, the boiler is the blue rectangle on the left. The dirty flue gas leaves the boiler as represented by the red line. It then travels through the air preheater which transfers heat from the flue gas into the combustion air going into the boiler. After leaving the air preheater, the flue gas travels through an electrostatic precipitator, then a flue gas desulfurization (FGD) unit, and then the flue gas is reheated in a second air preheater known as a gas-to-gas heat exchanger. Some supplemental heat is also added, either directly fired heat using natural gas or heat from a steam coil using steam from the boiler as the heat source. This page lists the possible sources of supplemental heat as steam or gas or oil. After the flue gas that has been cleaned by the ESP and FGD is reheated in the gas-to-gas heat exchanger with some supplemental heat, it passes through the SCR, then exits through the same gas-to-gas heat exchanger, which recycles the heat back into the flue gas entering the SCR. The SCR is on the "tail-end" of the system, thus the name. By the time the flue gas enters the 5CR in this tail-end configuration, it is as clean as it is going to be, in terms of particulate matter and sulfur oxides ("SOx") concentration. That is, the particulate matter and SOx levels are at or below the permit limits.

There are advantages and disadvantages to the various configurations. For example, in a tail-end SCR, one has to incur the added capital and operating expense of reheating the flue gas. However, because the flue gas is so clean, as compared to a high dust 5CR, one can built a smaller SCR to achieve the same amount of NOx reduction. Larger gas passages are needed in the SCR catalyst in high dust environments to avoid plugging of the catalyst, resulting in a proportionately larger SCR. The catalyst lasts much longer in the tail-end location because it is in the "clean" environment compared to the high dust configuration.

Petitioner's Ex. 5 has depictions of these configurations at the page numbered 4. There is a diagram of three of the configurations, that is, hotside high dust; hot-side low dust; and tail-end.

EKPC's final BACT analysis stated that "the presence of alkaline particulate matter emitted from a CFB boiler would preclude effective SCR operation due to catalyst poisoning. Therefore, operation of the SCR upstream of the particulate control equipment for a CFB boiler is technically infeasible." Jt. 31 at joint3l.0016. In other words, EKPC's application found that hot-side, high dust SCR was technically infeasible.

EKPC's final BACT analysis and DAQ statement of basis did not consider a hot-side, low dust SCR. Id. atJoint3l.0016 —Joint3l.0017. A hot- side, low dust SCR would require a hot-side electrostatic precipitator or fabric filter. Babcock and Wilcox, uses the first fields of electrostatic precipitator in hot-side locations on some of its CFBs. P107, page 1. Prior to the permit issuance for Spurlock 4, DAQ said that a hot-side ESP may cause SCR to be eliminated on economic, not technical feasibility grounds. P113 at 1.

EKPC's final BACT analysis found that a tail-end SCR with steam reheat was technically feasible. Jt. 31 at joint3l.0017. EKPC's BACT analysis specifically stated: "Based upon the discussions above, the two NOx add-on control options that remain as feasible options for BACT control of NOx, are (1) use of SCR with equipment necessary to reheat the gas stream after the baghouse, and (2) use of SNCR." Id.

Similarly, in the final document submitted by EKPC to the DAQ, Jt. 46 at joint 46.0004, EKPC again says that "EKP[C] did not reject SCR as being technically infeasible." In fact, in response to Sierra Club's comments, in Jt. 47 a tJoint47-0029, EKPC again said that "EKPC did no reject SCR as being technically infeasible." EKPC said in Jt. 47 at joint47-0029 that "instead EKPC did a cost analysis and concluded that SCR is not BACT due to economic considerations."

Prior to the issuance of the final permit for Spurlock 4, DAQ did not think rejection of SCR as technically infeasible was sufficiently defensible. P113 at 1. Specially, Mr. Newell wrote;

It appears that EPA has decided that they can live with the NOx BACT analysis, as submitted, as long as it comes up with a 0.07 lb/MMBtu (30-day average) limit. Tom still has one concern: For future defensibility, he believes (and I agree) that EKP should include a discussion of SCR (as opposed to SNCR) in their feasibility analysis. Odds are great that they'll kick it out for economic infeasibility (they'd probably have to add a hot side ESP and maybe a preheater prior to the SCR), but that'd be a lot stronger than what they've done up to now, which is to just say 'it's infeasible' and kick it straight out. Given the fact that there was a plant in Europe.(Tom can look up the details) that had an SCR, I don't think they should just dismiss it out of hand.

P113 at 1. EKPC'S BACT analysis rejected tail-end SCR with reheat based on economic impacts in light of collateral environmental impacts, not technical feasibility. Jt. 31 at joint3l.0019.

SCR is technically feasible for a CFB boiler in the Wellington case before the Pennsylvania Environmental Hearing Board. Similarly, in Montana for the proposed Highwood CFB, the applicant did not reject SCR in its BACT analysis as technically infeasible. Powers W.D. 37:9- 16. See also 11/2 Tr. 23:25 — 24:3 (Adams)("l am aware that it has been — it has been stated by both applicants and, you know, I guess the permitting officials that it's technically feasible.").

With regard to Spurlock 3, which is also a coal-fired CFB, DAQ did not conclude that SCR was technically infeasible. 11/2 Tr. 27:24 — 28:2. In the Spurlock 4 proceedings, both DAQ and EKPC maintain that SCR is technically infeasible for Spurlock 4. P90 at 3 (response to request for admission 10). However, in discovery DAQ admitted that it did not have sufficient knowledge to determine if tail-end SCR is technically feasible at Spurlock 4. P101 at 2, (Supplemental

Response to Request for Admission No. 7). Mr. Powers offered the opinion that SCR in a hot-side low dust or tail-end configuration is technically feasible for Spurlock 4 and that SCR in a hot-side high dust may be technically feasible for Spurlock 4. Though no evidence was admitted which showed there are any commercial scale SCRs operating on commercial scale coal-fired CFBs in the world, as of the date the Spurlock 4 permit was issued, there is at least one reference to a pilot scale CFB that burns coal and has a SCNR and SCR in a foreign language paper. PowersW.D. 29:19-20.

EKPC chose Alstom to provide it with the CFB for Spurlock 4. There are other CFB vendors such as Babcock and Wilcox and Foster Wheeler but EKPC did not solicit bids from these companies and did not supply any information about the CFB performance from these other companies. Alstom also built Spurlock 3. Babcock and Wilcox holds a patent for a high dust, hot side 5CR on a CFB. P1. The Babcock and Wilcox standard CEB design includes a multiple dust collector that reduces particulate loading to the point that Babcock and Wilcox feels a high dust SCR will function adequately if located downstream of the multiple dust collector. Powers W.D. 26:12-15.

SCRs are available for commercial sales and have been so for at least two decades. P5, at Table 3.2 which is on pages 7-9, shows an SCR begin operating in 1985 on the power plant labeled G-1. Power plant labeled G-4B, its tail-end SCR began operating in 1988. P75 is a list of many of the suppliers of SCRs, but it should not be considered a complete list of all the SCR vendors. Major SCR catalyst vendors such as CERAM, Hitachi Zosen, and Siemens are not included. Powers W.D. 32:3-4. Not all of these suppliers supply SCR5 for coal-fired power plants but most do.

SCRs are currently used on sources similar to coal-fired CFBs, especially with regard to the tail-end configuration. SCRs are used on coal- fired Pulverized Coal (PC) boilers in the tail-end as well as in the high-dust configuration. For example, there are the tail-end SCRs on PC boilers in Germany. These SCRs have operated very successfully for decades. Powers W.D. 32:12-16; P26 at pdf page 4, 5 & 6 (Herne Unit 3 burns high ash waste bituminous coal with tail-end SCR since 1988 with "extremely uneventful" operations."). There are also tail-end SCRs on coal-fired PC boilers in the United States. For example, PSE&G's Mercer plant in New Jersey has a tail- end SCR on a coal-fired PC. Powers W.D. 32:16-17. SCRs are also used in a variety of applications like refineries, steel mills, garbage incinerators, as well as natural gas boilers, simple-cycle gas turbines and combined-cycle combustion turbine applications, diesel stationary engines, and coal-fired power plants. Powers W.D. 32:4-7.

There are also coal-fired pressurized fluidized bed units that currently have SCR. The EPA paper that is P78 at p. 3-88 (PDF page 117) gives at least two examples. P2 shows the same thing; SCR on a coal-fired pressurized fluidized bed boiler. The 11th page, which is right after the end notes shows a coal-fired *pressurized circulating fluidized bed boiler with a SCR. Furthermore, there are SCRs on CFBs in Europe which burn fuels other than coal, such as biomass. Powers W.D. 32:17-18; P113 at 2.*

In understanding the difference between a CFB and a pressurized circulating fluidized bed boiler, it is important to note that when we say CFB, we actually mean atmospheric circulating fluidized-bed combustors. Atmospheric means the pressure is the boiler is basically at ambient atmospheric pressure. Powers W.D. 33:6-9.

In a pressurized fluidized bed combustor, the combustion process takes place in a pressurized environment. EPA says in P78 at page 3-86 (PDF page 115) "pressurized fluidized bed combustion (PFBC) is similar to AFBC in that it utilizes the fluidized bed technology, but the PFBC boiler operates under pressure (typically 1.2—1.6 MPa)." The SCR is located in a clean gas location on the PFBC units, effectively a tail-end gas location. Powers W.D.33: 12-13.

In terms of regulator decisions, tail-end SCRs are being considered in Best Available Retrofit Technology determinations for Portland cement plants despite the fact that there were none as of March, 2005. P56 is the Midwest Regional Planning Organization (RPO) Cement Best Available Retrofit Technology (BART) Engineering Analysis. At page 22, the Midwest RPO says that SCR has not been installed on cement kilns but is being evaluated as BACT for new cement kilns even though the flue gas would need to be reheated as in a tail-end SCR configuration on a coal-fired power plant. On page 36, the document explains that Midwest RPO found SCR to be technically feasible on a cement kiln despite essentially all the same arguments against SCR that EKPC makes in this case. Powers W.D. 33:19 — 34:11. EPA recently announced a Clean Air Act settlement that involves the installation of an SCR on a cement kiln in the United States.

Another example is lignite-fired power plants. Lignite is a type of coal. EPA noted that commentators on the new New Source Performance Standard for coal utility boilers indicated that lignite-fired units have never had SCR on them. Therefore, according to these commentators, SCR shouldn't be considered technically feasible for lignite boilers. EPA said that SCR should not be considered technically unfeasible simply because it had not been used in the past on this type of fuel in this type of unit. 71 Fed. Req. 9865, 9870 (Feb. 27, 2006). Powers W.D. 34:12-19.

Mr. Powers communicated with three SCR vendors who indicated they would provide and guarantee SCR performance on coal-fired CFBs if the SCR was in the appropriate configuration. He contacted Nate White of SCR vendor Haldor Topsoe about that issue. Mr. Powers put the question to Haldor Topsoe in three ways; will you provide a guarantee on a tail-end SCR on a coal-fired CFB? Mr. White said yes. Will you provide a guarantee on a SCR located after a hot ESP, such as EKPC has on Unit 2 at Spurlock? Mr. White said yes, we will. Will you *provide a guarantee on an SCR that is in a location directly downstream of the U-beams or cyclones on the CFB, meaning in a high-dust location? And his response was maybe, stating Haldor Topsoe would have to take a look at that location. Haldor Topsoe provides entire SCR systems in Europe. In the United States, they provide catalysts. When Mr. Powers asked Nate White about guarantees, he was asking him about complete SCR systems. During Mr. Powers' conversation, Haldor Topsoe was willing to guarantee for NOx 90 percent emissions reduction using a SCR on a coal-fired CFB unit. Powers W.D. 35:1-21.*

Haldor Topsoe's literature, P14, indicates they can achieve 98 percent removal. Haldor Topsoe recently had a sale to the developer of a 950- megawatt unit where the cost of the catalyst, the static mixer and ammonia injection grid and the modeling for the SCR -- the combined cost for a 950- megawatt PC was approximately $4 million. This was for 90 percent NOx control. It is a hot-side low dust application, on a PC after a hot ESP with exceptionally low $S0_2$ to SO_3 conversion. Powers W.D. 35:19 — 36:7.

Mr. Powers' testimony is consistent with e-mails from Mr. White that sent to EKPC. See EKPC3 & EKPC4.[100] In these e-mails, Mr. White raises no questions about a low dust SCR on a coal-fired CFB but does explain that the deactivation in the high dust position would be "high." 12/5 Tr. 67:4 — 69:20.

He basis this statement on his experience with SCRs on coal-fired power plants that burn Powder River Basin coal (PRB) coal. EKPC3.

Mr. Powers asked Haldor Topsoe about the calcium oxide poisoning issue. Mr. Powers told Mr. White that Mr. Powers did not know what the calcium oxide percentage in the fly ash is, but that he should assume that 100 percent of the particulate matter entering the SCR in a tail-end or low dust configuration was calcium oxide, and that this particulate level was at the permit limit. 100 percent of the particulate matter will not be calcium oxide but that is the most conservative assumption one can make. Mr. Powers asked that, if this is the case, would that pose a problem for Haldor Topsoe to guarantee its SCR. Mr. White said no. He said even if you assume 100% of the particulate matter level at the permit limit is calcium oxide, the particulate concentration is so low it would not even be a consideration in the guarantee of SCR performance. Powers W.D. 36:11 — 22. In EKPC Spurlock 2, a PC boiler, EKPC actually injects calcium oxide, in the form of kiln dust, to protect the SCR from arsenic poisoning. In the case of Spurlock 2 a certain level of calcium oxide is not only not a problem, it is desirable. Powers W.D. 36:22 — 37:2.

Mr. Powers also contacted Atsushi Akita at Hitachi Zosen U.S.A. Ltd. in Houston, Texas, and Tony Zavale of Hitachi America in New York. Both Hitachi Zosen and Hitachi America indicated they would guarantee 90% NOx reduction on a coal-fired CFB. Powers W.D. 37:4-7.

Mr. Powers also spoke to Don Wietzke, one of the patent holders of P1, who told him that Babcock and Wilcox obtained this patent because they assumed air pollution regulations would eventually require NOx emission limits below what a CFB with a SNCR can achieve.

Therefore, because a hot side SCR is technically feasible, DAQ must base BACT for NOx for CFB 1 and 2 on the use of an SCR.

Division's Response to Comment IV-B2:
The Division does not concur that a high dust SCR on a CFB is technically feasible at this time and does not agree that the comments made by the commentors support their conclusion. For example, on page 68 of comments received from Mr. Ukeiley, the commentor states:

> "*Will you provide a guarantee on an SCR that is in a location directly downstream of the U-beams or cyclones on the CFB, meaning in high-dust location? And his response was maybe, stating Haldor Topsoe would have to take a look at that location*"
> and
>
> "*...Mr. White raises no questions about a low dust SCR on a coal-fired CFB but does explain that the deactivation in the high dust position would be "high"*"

Kentucky has reviewed the materials submitted, and is not convinced high dust SCR technology has been proven to be technically feasible in conjunction with a CFB. The commentor's first referenced document "IV-B-2-1" is a summary of an analysis performed by another state agency (Virginia) that references the Santee Cooper permit project as a CFB with SCR. The Division is aware of a permit issued by South Carolina for a PC unit for Santee Cooper, but has been unable to discover any permit or application for a CFB by Santee Cooper.

The Division notes the second exhibit is "IV-B-2-2" is a declaration by Phyllis Fox supported by unnamed employees of several catalyst suppliers. However, the type of SCR and the level of performance were not detailed in the comment or declaration. The Division also reads the document as indicating that Alstom was installing a SCR system on a CFB, but when the Division contacted Alstom, Alstom confirmed that they were not in the process of installing any such device on any coal fired unit. Alstom, a major supplier for SCR technology has stated that they do not find that a SCR is technically feasible on a CFB. The exhibit also claims that no problems were experienced during a testing by CERAM, a catalyst supplier, at EKPC Spurlock. The Division is unsure how the author of this exhibit could present this fact without any documentation of actual testing results. The Division has searched literature and websites for a single example of a proposal to install a SCR on a coal-fired EGU CFB. There is still a lack of published articles on any test projects. The Division concurs that a high dust SCR is undemonstrated technology that is neither available nor applicable.

The Division has not been present nor has any access to any testing results that may have been performed at EKPC Spurlock for the purposes of technical evaluation of SCR technology at a CFB.

Comment IV-B3:

3. TAIL END SCR IS COST EFFECTIVE.

Other agencies have permitted SCRs on coal fired CFBs. See Ex. IV-B-2-1. Multiple vendors will guarantee an SCR on a coal-fired CFB. See Ex. IV-B-2-2, para. 2-4. In fact, EKPC itself has successfully pilot tested an SCR on its coal fired CFB and is now planning on building one. See Ex. IV-B-2-2, para. 4. Thus, it is not surprising that once again takes the position that tail end SCR is technically feasible on a coal-fired SCR.

However, the SOB rejected tail-end SCR with a high temperature catalyst that because DAQ thought it was not cost effective. Fixing just one error in the analysis would change this.

*Footnote 14 of the SOB references a letter from Alstom that states that the reheat of the flue gas for a tail-end SCR would require 246 MMBtu of natural gas per hour. However, that April 2, 2008 Alstom letter is reference a once through reheat system. Once through means it would not have a gas to gas heat exchanger to recycle the heat. Alstom notes that this is "not a commonly used system with this configuration" meaning it doesn't make sense to do it that way. Footnote 15 of the SOB references a letter from Alstom that gives a $60 million capital cost for a tail-end SCR system for Smith 1 that includes a gas to gas heat exchanger. See SOB at 21. Then the cost analysis in Table 5-2 takes the natural gas requirements for a tail end SCR without a gas to gas heat exchanger and the capital cost of a tail end SCR with a gas to gas heat exchanger and computes a dollars per ton removed figure of $18,330. This is arbitrary. One cannot use the capital cost of one system and the operating cost of another different system. With a gas to gas heat exchanger, the reheat requirement would be 47 MMBtu/hr rather than 246 MMBtu/hr. See Jt. Ex. 24 from Spurlock 4 case attached as Ex. IV-B3-2 at pdf page 5. The cost of the natural gas reheat, even using the inflated price of natural gas in the SOB would be 9.873/MMBtu * 47 MMBtu/hr * 8760 = $4,064,911.56. This is $17,211,008.44 cheaper than the estimate in Table 5-2. The natural gas would also only generate 34 tons per year of additional NOx, with 31 of them removed by the SCR. 47/246 * 180 * ,9 = 30.95. Total annual costs would be 32,516,050 — 17,211,008.44 = $15,305,041.56. Tons removed would be 1774— (160-31) 1645. $15,305,041.56 / 1645 = $9303.98 per ton. In 2001, U.S. EPA determined that a $10,000/ton control cost ceiling was reasonable for NOx and SO_2 in attainment areas. See expert report of Matt Haber - EPA, Best Available Control Technologies for the Baldwin Generating Station, Baldwin, Illinois, prepared for the United States in connection with United States v. Illinois Power Company and Dynegy Midwest Generation, Inc., Civil Action 99-883-MJR, in the U.S. District Court for the Southern District of Illinois, April 2002, p. 17; Memorandum of John S. Seitz to Air Division Directors, BACT and LAER for emissions of nitrogen oxides and volatile organic compounds at Tier 2/Gasoline Sulfur Refinery Projects (Jan. 19, 2001), at 3. Today that figure would* *be substantially higher. For example, other utilities are incurring costs of $15,400 per ton of NOx removed. Ex. IV-B-3-1 at 12. However, even using the $10,000 per ton figure, tail-end SCR is cost effective. Therefore, DAQ needs to rest the BACT limit based on SCR to 0.015 Ib/MMBtu on an annual basis.*

Finally, the SOB claims that the NOx BACT limit is more stringent than the NOx NSPS but does not provide any basis for this claim, especially considering various loads. The SOB must document this claim.

Division's Response to Comment IV-B3:

The Division does not concur. In response to the comments received, EKPC provided a revised cost analysis for a tail end SCR. After review, the Division concludes that a tail-end SCR with low temperature catalyst is currently not feasible and that a tail-end SCR with a high temperature catalyst is not cost-effective.

Comment IV-B4:

4. DAQ MUST SET A BACT LIMIT FOR NOx EMISSIONS DURING STARTUP, SHUTDOWN AND MALFUNCTION.

The Draft Permit sets a BACT limit for NOx but then makes it not applicable during startup, shutdown and malfunction (ssm). Draft Permit at 22, Condition B.2.b.ii. There are not BACT emission limits for NOx during ssm in the Draft Permit. BACT is an emission limit. The permit must have emission limits based on a BACT analysis that apply to the CFBs' NOx emissions during SSM.

Division's Response to Comment IV-B4:

The Division does not concur. As noted in the Division's Response to Comment III-B2, there is no SSM exemption from the permit limit in Section B.2.c.iii. (Note, Section B.2.b. relates to SO_2, not NO_X). The BACT limit applies at all times.

Comment IV-C1:

C. SOX BACT

1. THE PERMIT LACKS SO_2 EMISSION LIMITS DURING STARTUP, SHUTDOWN AND MALFUNCTION

The Draft Permit sets a BACT limit for SO_2 but then makes it not applicable during startup, shutdown and malfunction (ssm). Draft Permit at 22, Condition B.2.b.ii. There are not BACT emission limits for SO_2 during ssm in the Draft Permit. BACT is an emission limit. The permit must have emission limits based on a BACT analysis that apply to the CFBs' $S0_2$ emissions during SSM.

Division's Response to Comment IV-C1:

The Division does not concur. There is no exemption from the permit limit in Section B.2.b.iii.

Comment IV-C2:

2. BACT MUST BE BASED ON WET SCRUBBER TECHNOLOGY.

BACT must be based on the most effective pollution control option available. As noted elsewhere in these comments, cleaner fuels (with appropriate additional post-combustion controls) are the most effective pollution control option. If BACT is not based on clearer fuels, the use of the more effective wet scrubber technology should be used as the basis for SO_2 BACT. Wet scrubber technology is commercially offered for CFBs. See Ex. IVC-2-1. at second page.

Division's Response to Comment IV-C2:
The Division does not concur. See the Division's Response to Comments IV-C2a through IV-C2i.

Comment IV-C2a:

a. BACKGROUND ON COST EFFECTIVENESS ANALYSIS

Cost considerations in determining BACT are expressed in one of two ways: average cost effectiveness or incremental cost effectiveness. NSR Manual at B.36[101]; see also Inter-Power, 5 E.A.D. at 136.

Average Cost Effectiveness. *The first step in calculating the average cost effectiveness of alternative control options (such as coal plus scrubber vs. natural gas clean fuel), is for DAQ to correctly define the baseline emission rate. Baseline emission rates are "essentially uncontrolled emissions, calculated using realistic upper boundary operating assumptions," for the applicant's proposed fuel choice. See NSA Manual at B.37.[102] Once the baseline is calculated, the cost-per - ton of pollutant controlled is calculated for each control option by dividing the control option's annualized cost by the tons of pollution avoided ("Baseline emissions rate — Control option emission rate"). In re Steel Dynamics, 9 E.A.D. 165, 202 n.43(EAB 1999); In re Masonite Corp., 5 E.A.D. 551, 564 (EAB 1994); NSA Manual at B.36-.37.*

Incremental Cost Effectiveness. *Incremental cost effectiveness is an optional consideration that must always be paired with average cost effectiveness. NSR Manual at B.41 ("incremental cost effectiveness should be examined in combination with the total cost effectiveness in order to justify elimination of a control option."), B.43 ("As a precaution, differences in incremental cost among dominant alternatives cannot be used by itself to argue one dominant alternative is preferred to another."). The NSR Manual warns that "undue focus on incremental cost effectiveness can give an impression that the cost of a control alternative is unreasonably high, when, in fact, the total cost effectiveness, in terms of dollars per total ton removed, is well within the normal range of acceptable BACT costs." Id. at B.45-.46.*

The use of incremental cost effectiveness is limited. It is only used to compare "dominant" alternative pollution control options. NSR Manual at B.43. This requires plotting all pollution control options to create an "envelope of least-cost alternatives" "depicted by the curvilinear line connecting" the control options. NSR Manual at B.41-.43 and Figure B-1. Incremental cost effectiveness is the difference in total annual costs between two contiguous control options that are on the dominant control curve. Id. The consideration of incremental cost effectiveness is not to be used to reject an option merely because it costs more—even if it costs twice as much—as the next dominant alternative. Id. at B.43.

<u>Determining Cost Effectiveness.</u> When determining if a pollution control option has sufficiently adverse economic impacts to justify rejection of that option and establishment of BACT on a less effective option, KDAQ must determine that the cost-per-ton of emissions reduced is beyond "the cost borne by other sources of the same type in applying that control alternative." NSR Manual at B.44; see also Steel Dynamics, 9 E.A.D. at 202; Inter-Power, 5 E.A.D. at 135 ("In essence, if the cost of reducing emissions with the top control alternative, expressed in dollars per ton, is on the same order as the cost previously borne by other sources of the same type in applying that control alternative, the alternative should initially be considered economically achievable, and, therefore, acceptable as BACT" (quoting NSR Manual at B.44) (emphasis original)).

In a cost-effectiveness determination, the cost of controlling SO_2 with a wet scrubber, the cost of a wet scrubber at Smith must be compared to the cost of controlling pollution <u>with a wet scrubber</u> at other facilities in the same source category. This consideration <u>does not</u> compare the cost-per-ton of air pollution with one pollution control option to the cost-per-ton of another pollution control option. This is consistent with the rule for BACT analyses that the collateral impacts provision (including cost-effectiveness) "operates primarily as a safety valve whenever unusual circumstances specific to the facility make it appropriate to use less than the most effective technology." In re Columbia Gulf Transmission Ca, 2 E.A.D. 824, 827 (Adm'r 1989) (emphasis added).

It is also important to note that a pollution control option must be outside the range of costs borne by facilities in the same source category, <u>plus the margin of error,</u> to be determined not cost effective. Cost calculations used in BACT determinations are only assumed to be accurate within 20 to 30 percent. Therefore, EPA's guidance concludes that this uncertainty is resolved in favor of defaulting to the most pollution control:

> *Study cost estimates used in BACT are typically accurate to ± 20 to 30 percent. Therefore, control cost options which are within ± 20 to 30 percent of each other should generally be considered to be indistinguishable when comparing costs.*

NSR Manual at B.44. Therefore, generally a pollution control option must be outside this margin, i.e., be more than 20-30% more expensive than other sources controlling air pollution with the same technology for a control option to be eliminated in a top-down BACT analysis.

Division's Response to Comment IV-C2a:

The Division does not concur with the commenter's interpretation. Requiring the expenditure of several million dollars in additional costs for a 0.1 percent reduction is not reasonable. Incremental costs can, and should, be used to reveal situations where large sums might be expended for very small gains.

It would be unreasonable for the Division to require the applicant to spend $7.8 million more per year, or 250 percent in increased costs, to achieve 0.1 percent difference in tons of SO2 removed, if in fact, that difference could be achieved.

Comment IV-C2b:

b. DAQ AGREES THAT THE AVERAGE COST EFFECTIVENESS OF WET SCRUBBING CANNOT BE USED TO REJECT THE TECHNOLOGY.

DAQ notes that a wet scrubber is cost-effective, while costing slightly more than a dry scrubber. SOB at 28 ("Both systems are cost effective at... $939.49 per ton for WFGD."). Nevertheless, without following the top-down process set forth in EPA's guidance that DAQ claims to follow, DAQ concludes that BACT should be based on the less-effective dry scrubber technology because "WFGD is considerably more expensive on cost per ton of SO_2 removed basis." Id. This is not a recognized or appropriate basis for selecting a BACT technology. More effective technologies cannot be rejected merely because they cost more than a less-effective technology or BACT analyses would default to the least-cost, no-control options.

It is EKPC's obligation to show that the cost of the more effective Wet FGD is not "cost-effective" compared to the cost of controlling SO_2 elsewhere. "The top-down approach places the burden of proof on the applicant to justify why the proposed source is unable to apply the best technology available," Citizens for Clean Air v. EPA, 959 F.2d 839, 845 (9th Cir. 1992), citing In re: Spokane Regional Waste-to-Energy Applicant, PSD Appeal No. 88-12 (EPA June 9, 1989), at 9 (internal quotation marks omitted) (emphasis in original); see also In re: Inter-Power of New York, Inc., 5 E.A.D. 130, 135 (EAB 1994) ("Under the 'top-down' approach, permit applicants must apply the most stringent control alternative, unless the applicant can demonstrate that the alternative is not technically or economically achievable."); In re Pennsauken County, New jersey Resource Recovery Facility, 2 E.A.D. 667 (Adm'r 1988), available at 1988 EPA App. LEXIS 27, 28 (Nov. 10, 1988) ("Thus, the 'top-down' approach shifts the burden of proof to the applicant to justify why the proposed source is unable to apply the best technology available."). That has not been done.

Division's Response to Comment IV-C2b:
The Division does not concur. The difference in estimated control efficiencies between the selected BACT option and a wet scrubber is 0.1 percent, while the selected BACT option has an annual cost of $5.2 million and wet scrubbing has an annual cost of $13 million. It would be unreasonable for the Division to require the applicant to spend $7.8 million more per year, or 250 percent in increased costs, to achieve 0.1 percent difference in tons of SO2 removed, if in fact, that difference could be achieved. The analysis did not consider the additional cost of a dewatering pond or waste treatment facility, or consider the additional particulate matter and sulfuric acid mist, or the effect that wet flue gas would have on a fabric filter. Therefore, the Division does not have any justification for requiring a wet scrubber.

Comment IV-C2c:

c. DAQ INCORRECTLY CALCULATED AVERAGE COST EFFECTIVENESS OF A WET SCRUBBER.

As noted above, average cost effectiveness must be calculated based on the reduction of emissions from a baseline representing uncontrolled emissions. NSR Manual at B.37. Here, the uncontrolled emission rate is 98,550 tons of SO_2 per year. See SOB p. 26, Table 5-6 (showing uncontrolled $S0_2$ emissions as 98,550 TYP). Using this correct baseline rate, the average cost-effectiveness of wet scrubbing technology, using KDAQ's assumptions regarding cost and removal efficiency is:[103]

Total Annualized Cost of Wet EGO from SOB Table 5-7	*$13,054,721.13*
Uncontrolled SO2 baseline from SOB Table 5-6	*98,550 tons*
Outlet SO2 from SOB Table 5-7	*886.92 tons*
$S0_2$ removed	*97,663.08 tons*
Cost per ton removed	*$133.67/ton*

As this calculation shows, when the correct baseline is used, the cost of a wet scrubber is even more cost effective.

Division's Response to Comment IV-C2c:
The Division does not concur. Limestone injection into the boiler achieves 85 percent of SO2 removal, which requires some inert material to be added to ensure proper operation. It is incorrect to attribute the reduction achieved by limestone injection to the wet scrubber.

Please refer to the Division's response to EPA's Comment 3 in Appendix A.

Comment IV-C2d:

d. DAQ UNDERESTIMATES THE CONTROL EFFICIENCY FROM A WET FGD.

In a cost effectiveness analysis, the more pollution is removed with a control option, the less the option costs in dollars-per-ton-removed. Here, DAQ has underestimated the control achievable with a wet FGD system, therefore falsely inflating its cost effectiveness. In Table 5-7 of the SOB, DAQ estimates the annual SO_2 at the inlet to the scrubber to be 14,782.50 tons per year and estimates the annual $S0_2$ at the outlet of the scrubber to be 886.95 tons per year, which represents an emission rate of 0.0675 lb/MMBtu. This represents only a 94% control across the scrubber. However, at least 99% control is achievable across the scrubber with a Wet FGD, which is in addition to control achieved through the limestone injection into the boiler.[104]

Over twenty years ago, Mitchell power station Unit 33 (Alleghany Power), a 292-MW generating unit near Pittsburgh, was retrofitted in 1982 with a magnesium-enhanced lime ("MEL") wet FGD system pursuant to a Consent Decree.[105] *Data is available for four months during 1983 and 1984 for that unit. The daily average SO_2 emission rate was 0.009 lbs/MMBtu and the daily average $S0_2$ removal efficiency was 99.76%. The maximum monthly average during these four months was 0.029 lb/MMBtu, corresponding to a 99.72% SO_2 reduction. Thus, over 99% reduction of SO_2 was being achieved more than two decades ago. Using a 0.03 lb/MMBtu emission rate, rather than the 0.675 lb/MMBtu rate used by EKPC and DAQ to calculate cost effectiveness, results in total annual emissions of 394.2 tons of $S0_2$ and a lower dollar-per-ton than assumed by DAQ in its SOB.*

Total Annualized Cost of Wet FGD from SOB Table 5-7	*$13,054,721.13*
Uncontrolled SO_2 baseline from SOB Table 5-6	*98,550 tons*
Inlet SO_2 (after partial control from limestone bed) from SOB Table 5-7	*14782.50*
Outlet SO_2 from SOB at 0.03 lb/MMBtu	*394.2 tons*
SO_2 removed from uncontrolled baseline	*98155.8 tons*
$S0_2$ removed from partially controlled baseline	*14388.3 tons*
Cost per ton removed from uncontrolled baseline	*$133.00/ton*
Cost per ton removed from partially-controlled baseline	*$907.32/ton*

Furthermore, using a more representative 0.03 lb/MMBtu outlet rate for a Wet FGD would cut the incremental cost-effectiveness in half, compared to the incremental cost assumed in DAQ's SOB.

Other examples of the higher effectiveness of Wet FGD are numerous. In a paper discussing the actual operating performance of the Chiyoda JBR or CT-121 wet scrubber technology in Japan notes that $S0_2$ removal efficiency of greater than 99% was achieved for all load levels and that a "[s]table SO_2 removal efficiency of over 99 percent" was achieved.[106] *Additionally, Chiyoda's experience list shows at least three instances of 99% removal.*[107] *Similarly, Mitsubishi Heavy Industries ("MHI"), another reputable vendor of wet scrubbers, has a design called the High Efficiency Double Contact Flow Scrubber ("DCFS"), which has achieved SO_2 removal efficiencies as high as 99.9%. A* *presentation on the DCFS scrubber highlights the fact that it can be designed to achieve SO_2 removal efficiencies as high as 99.9% on a unit that burns high sulfur coals without the use of buffer additives.*[108] *The manufacturer, MHI, guarantees SO_2 removal of 99.8%.*[109] *A 2004 paper discussing the DCFS scrubber technology notes that this technology was recently selected at least two years ago by TVA for their Paradise Plant Unit 3, which was scheduled to start up in early 2007.*[110] *This paper also reports on several recent commercial operating successes with this technology "including super high desulfurization performance (i.e., 99.9%) with a single absorber."*[111] *The paper also notes that the COSMO oil Yokkaichi unit is an outstanding example of high SO_2 removal by a single counter current DCFS. Commercial operation at COSMO began in 2003, and the FGD system has achieved a cumulative availability of 100 percent since startup. The system is designed at 99.5% and operates at 99.9% SO_2 removal efficiency.*

A different variant of the wet scrubber technology —FLOWPAC — has demonstrated an $S0_2$ removal efficiency of over 99%.[112] *From November 2002 to March 2003, Karlshamn Unit 3 operated for 2152 continuous hours while firing a heavy fuel with an average sulfur content of 2.4%: The $S0_2$ emissions during this period were kept to 21 mgINm3, which is an $S0_2$ efficiency of 99.5% with an S efficiency of 99%. During this period the FGD system was 100% available.*

Lastly, another vendor, Alstom, recently discussed high efficiency scrubbing on high sulfur fuels. As noted in the paper "[t]o date, the wet flue gas desulfurization system has achieved 100% availability while achieving the plant SO_2 emissions limits throughout the operating duration.. ..as indicated.. .the WFGD system has achieved SO_2 removal efficiencies up to 99+% without the use of organic additives."[113]

These operating experiences clearly show that greater than 99% control from the Wet FGD device, alone, is achievable. Total emissions from the Smith units after installation of Wet FGD would be lower than used in DAQ's SOB and, therefore, the cast effectiveness and incremental cost effectiveness analysis would show even lower costs per ton of SO_2 removed.

Division's Response to Comment IV-C2d:

The Division does not concur. As previously noted, the Division has already concluded that WFGD is cost-effective on an average cost basis. EKPC selected CFB with limestone injection and FDA using fresh lime injection. EKPC provided cost analyses comparing its selected option with WFGD, the use of lower sulfur coal, and the use of washed coal. However, as can be seen from the above table, the difference between EKPC's selected option and WFGD is marginal.

Please refer to the Division's response to EPA's Comment 3 in Appendix A.

Comment IV-C2e:

e. DAQ FAILED TO APPORTION THE COST OF WET FGD TO ALL POLLUTANTS THAT WILL BE CONTROLLED WITH THE WET FGD.

*DAQ's SOB separately calculates the cost effectiveness of a Wet FGD for **S02** and sulfuric acid mist. SOB at 26-28, 33-35. However, when calculating the cost of a control option which reduces emissions of numerous pollutants at the same time, the cost of that control option must be divided between the overall reduction in all pollutant emissions. EPA guidance states that when a control option controls multiple pollutants the costs are to be apportioned to each pollutant before the $/ton is figured for cost effectiveness. See Ltr. from Brian L. Beals, Chief Preconstruction/HAP Section, USEPA Air and Radiation Technology Branch, to Edward Cutrer, Jr., Program Manager, Georgia Dept. NatI Resources (March 24, 1997). Responding to a question by Georgia permitting authorities of how to account for a control device that reduces both VOC and CO, EPA agreed with the Georgia agency's interpretation that the cost effectiveness should be calculated by "dividing the annualized cost of the control device by the total of the CO and VOC emissions reduced by said device." Id. Here, the cost of a Wet FGD must be divided by the total reduction of all pollutants reduced with that device.*

Total Annualized Cost of Wet FGD from SOB Table 5-7	*$13,054,721.13*
SO, removed	*97,663.08 tons*
SAM removed from SOB Table 5-10	*526 tons*
Total pollutants removed	*98,189.08 tons*
Cost per ton removed	*$132.95/ton*

Thus, using DAQ's own numbers, the cost-per-ton of pollutant removed is significantly lower than the SOB suggest. KDAQ admits that Wet FGD is cost effective based on average cost effectiveness when only SO2 is considered. This is even more true when DAQ's error in failing to spread the cost across multiple pollutants is corrected.

<u>Division's Response to Comment IV-C2e:</u>
The Division does not concur. Since the Division had already concluded that WFGD is cost-effective on an average cost basis, it was unnecessary to consider additional pollutants. That is, WFGD is cost-effective for removing SO2. If SAM is also considered in the analysis, WFGD is still cost-effective. It should be noted that FDA is also effective at removing SAM, if not more so, since FDA is a dry process and hence less likely to form SAM.

<u>Comment IV-C2f:</u>

f. DAQ IMPROPERLY REJECTED WET SCRUBBING BASED ON INCREMENTAL COST EFFECTIVENESS.

As noted above, the SOB admits that wet scrubbing is cost effective based on average cost effectiveness (which is especially true when the correct baseline emissions are used), but then rejects wet scrubbing based on incremental cost-

effectiveness. SOB at 28. This is improper. Incremental cost effectiveness can only be used in combination with average cost effectiveness to reject a technology that is not cost effective under either average or incremental cost effectiveness. NSA Manual at B.41 ("incremental cost effectiveness should be examined in combination with the total cost effectiveness in order to justify elimination of a control option."), B.43 ("As a precaution, differences in incremental cost among dominant alternatives cannot be used by itself to argue one dominant alternative is preferred to another."). As a result, DAQ's analysis presents the misleading scenario that the NSA Manual warns of: "undue focus on incremental cost effectiveness can give an impression that the cost of a control alternative is unreasonably high, when, in fact, the total cost effectiveness, in terms of dollars per total ton removed, is well within the normal range of acceptable BACT costs." NSA Manual at B.45-.46.

Moreover, DAQ offers no justification or explanation. The SOB merely states that the difference between wet scrubbing and dry scrubbing is $79,378 per ton of SO2 and concludes that this is not cost effective. KDAQ fails to explain why an incremental cost of $79,378 per ton is not cost effective, especially when the average cost effectiveness is so low. See In re if. Ky. Power Coop. Inc Hugh L. Spurlock Generating Station, Petition IV- 2006-4, Order at 29 (Adm'r, August 30, 2007) (objecting to a permit for the EKPC Spurlock plant where KDAQ failed to sufficiently explain the basis for not establishing BACT on a more effective control option).

Division's Response to Comment IV-C2f:
The Division does not concur. Please refer to the Division's responses to Comment IV-C2b, Comment IV-C2c, Comment IV-C2d, and Comment IV-C2e.

Comment IV-C2g:

g. DAQ DID NOT COMPARE THE AVERAGE COST EFFECTIVENESS OF WET FGD AT SMITH TO THE COST OF WET FGD AT OTHER SOURCES.

As noted above, the central consideration in assessing cost- effectiveness is whether the cost of implementing a pollution control option at the permitted source is beyond "the cost borne by other sources of the same type in applying that control alternative." NSA Manual at B.44 (emphasis added); see also Steel Dynamics, 9 E.A.D. at 202; Inter-Power, 5 E.A.D. at 135. The NSA Manual also states that "where a control technology has been successfully applied to similar sources in a source category, an applicant should concentrate on documenting significant cost differences, if any, between the application of the control technology on those sources and the particular source under review." NSA Manual at 8. 31 (bold emphasis original, other emphasis added). DAQ's SOB contains no finding regarding the cost of the control technology (Wet FGD) at Smith and the cost of the same control technology at other sources. Therefore, it cannot properly reject Wet FGD.

Division's Response to Comment IV-C2g:

The Division does not concur. First, it is undisputed that WFGD is cost-effective on an average cost basis so there was no need to compare to other facilities. Second, the Division is not aware of any CFBs operating with WFGD as a control device.

Comment IV-C2h:

> *h. DAQ MUST CALCULATE THE AVERAGE COST EFFECTIVENESS FOR THE ENTIRE POLLUTION CONTROL TRAIN, INCLUDING FUEL.*
>
> *As noted above, clean fuels must be considered in a BACT analysis and KDAQ's consideration was faulty. Once that is correct, KDAQ must recalculate average cost effectiveness of the Wet FGD. Cost effectiveness is the ratio of the control option annualized cost divided by the control option annual emission reduction. NSA Manual at B.36-B.37. The control option includes the entire combination of controls that, together, reduce SO2 emissions. A clean fuel paired with an end-of-the-pipe control device like a scrubber is one pollution control option. In other words, to calculate average cost effectiveness, the numerator should be the cost of the entire pollution control train, including both the scrubber and the fuel.*

Division's Response to Comment IV-C2h:

The Division does not concur. The Division concluded that WFGD is cost-effective on an average cost basis.

Comment IV-C2i:

> *i. THE OTHER BASES DAQ PUTS FORTH FOR REJECTING WET SCRUBBING AS THE BASIS FOR BACT— PURPORTED ENVIRONMENTAL AND ENERGY COLLATERAL IMPACTS—ARE INSUFFICIENT TO JUSTIFY REJECTING THE MORE-EFFECTIVE WET SCRUBBING TECHNOLOGY.*
>
> *The SOB and EKPC's application also make irrelevant reference to general energy and environmental impacts of Wet FGD, presumably to indicate that those collateral impacts justify use of the less effective dry scrubbing device to establish BACT limits. This is improper.*
>
> *A top-ranked control option must be used to set a BACT limit unless, in limited circumstances, energy, environmental, or economic issues justify rejecting the top-ranked control for a less effective option. NSA Manual at B.26-B.29. The legal authority to reject the top control option based on energy, environmental and economic impacts is referred to as the "collateral effects clause" of the BACT definition. The purpose of the collateral impacts clause is to accommodate site-specific issues that may prevent the use of the best control technology. Senate Debate on S.252 Oune 8, 1977), reprinted in 3 Senate Committee on Environment And Public Works. A Legislative History of the Clean Air Act Amendments of*

<u>1977</u> at 729 (Comm. Print August 1978) (Congressional Research Service, Serial No. 95-16) (the purpose of the collateral impacts clause is to allow for differences between regions in the country, feedstock and plant configuration while still maximizing the use of improved technology).

Citing congressional intent, EPA has repeatedly interpreted the "collateral impacts clause" as only allowing the rejection of the top control option when impacts <u>unique to the specific facility</u> being permitted make the top control inappropriate <u>at that specific site.</u>

> *The Administrator has explained that the primary purpose of the collateral impacts clause is to temper the stringency of the technology requirements whenever one or more of the specified collateral impacts- energy, environmental or economic- renders the use of the most efficient technology inappropriate. The clause allows rejection of the most effective technology as BACT only in limited circumstances. The collateral impacts clause operates primarily as a safety valve whenever unusual circumstances specific to the facility make it appropriate to use less than the most effective technology. Unless it can be demonstrated to the satisfaction of the permit issuer that such unusual circumstances exist, then the permit applicant must use the most effective technology.*

In re Kawaihae Cogeneration Project 7 E.A.D. at 116-17 (emphasis original) (quoting In re Columbia Cuff Transmission Company, PSD Appeal No. 88-11 4-6, 2 E.A.D. 824, 826 (Adm'r June 21, 1989)); In re Old Dominion Elec. Coop., 3 E.A.D. 779, 792 (Adm'r 1992)). EPA's NSR Manual confirms that the collateral impacts must be unique and unusual to the permitted source, the collateral impacts clause is to be used to reject a control option that has the same collateral impacts everywhere that the control option is used.

> *The determination that a control alternative to be [sic] inappropriate involves a demonstration that circumstances exist at the source which distinguish it from other sources where the control alternative may have been required previously.... In the absence of unusual circumstances, the presumption is that sources within the same source category are similar in nature, and that [they can bear the same] cost and other impacts.*

NSA Manual at B.29; see also Masonfte Corp., 5 E.A.D. at 564. If it were otherwise-- if the collateral impacts analysis allowed an applicant to reject the top option based on impacts common to the control device, rather than unique to the facility-- the top option would rarely be used, and the intent to "maximize the use of improved technology" would be thwarted. 3 <u>Legislative History of the</u>

Clean Air Act Amendments of 1977 at 729 (congressional intent to maximize the use of the best technology).

The burden to demonstrate that a source cannot use the top control option because of collateral impacts unique to the source is an intentionally heavy burden. As EPA has repeatedly stated, the collateral "energy, environmental, or economic impacts" exception to the top-control option is narrow, to be used sparingly on unique circumstances at the source.

> *The [collateral impacts] clause [of the BACT definition] allows rejection of the most effective technology as BACT only in limited circumstances. The collateral impacts clause operates primarily as a safety valve whenever* ***unusual circumstances specific to the*** *facility make is appropriate to use less than the most effective technology.*

In re Kawaihae Cogeneration Project 7 E.A.D. 107, 116-17 (EAB 1997) (emphasis original); see also/n re World Co/or Press, Inc., 3 E.A.D. 474, 478 (Adm'r 1990) (collateral impacts clause focuses on the specific local impacts). To reject wet scrubbing for the Smith units, therefore, EKPC would have to not only show collateral impacts unique to those units, but also support that showing with objective and documented analysis. NSR Manual at B.26-B.29; KnaufL 8 E.A.D. at 131 ("A permitting authority's decision to eliminate potential control options as a matter of technical infeasibility, or due to collateral impacts, must be adequately explained and justified.").

Neither EKPC nor DAQ conducted an analysis of the facility-specific collateral impacts. The few impacts mentioned for a wet scrubber device are hardly unique to Smith, but would be applicable to any wet scrubber device (and many of them could be mitigated in any event). In fact, EKPC's application refers generally to "WFGD systems" in the energy and environmental impact analysis, rather than to the Smith site in particular, and speculates about "likely" but not documented issues. EKPC Application § 4.3.3.4.

Division's Response to Comment IV-C2i:
The Division does not concur. Although adverse collateral impacts exist, they were not the basis for rejection of WFGD.

Division's Response to Comment IV-D1:

D. OTHER POLLUTANTS
1. SULFURIC ACID MIST

The SOB acknowledges that there are other CFBs with lower sulfuric acid mist BACT limits than the Smith CFB5. SOB at 36. The SOB attributes this to the high sulfur content of EKPC design coal. However, DAQ and EKPC failed to consider *using lower sulfur coal, biomass in the form of switchgrass, a subcritical PC, a supercritical PC, a supercritical CFB, or IGCC as control technology options for sulfuric acid mist. See SOB at 33-34. Low sulfur coal would include PRB coal but it would also include 100% low sulfur, e.g. 1%, Central or Northern Appalachian coal. This would mean not burning waste coal. In addition, DAQ failed to consider combinations of these alternatives.*

For example, BACT could be based on a requirement that EKPC switch the waste coal and run of mine coal ratios in its design coal so that the design coal is 1.5% sulfur rather than 3% sulfur. This would result in a BACT limit equal to the BACT limits in the four other sources EKPC identified as currently having lower sulfuric acid mist BACT limits. All of these measures are available and technically feasible as they are all in common use with the exception of switchgrass which as noted elsewhere in these comments EKPC admits is technically feasible. Thus, DAQ must re-do the sulfuric acid mist BACT analysis to consider available control measures and allow the public an opportunity to comment on that analysis. We further discuss this issue in section IV.E, below.

<u>Division's Response to Comment IV-D1:</u>
The Division concurs. The Division has revised the H_2SO_4 BACT information in the Statement of Basis.

<u>Comment IV-D2:</u>

2. LEAD
There is no lead BACT limits for CFBs 1. & 2 in the draft permit, not discussion of BACT for lead in the SOB and no BACT analysis for lead in the permit application. The SOB does state that the uncontrolled lead emissions are 40.26 tons per year. This is well over the 0.6 tpy significance threshold. The SOB claims that the CFBs potential to emit is 0.17 tpy, presumably based on the operation of the controls. However, the draft permit does not have enforceable conditions to assure compliance with the claimed 0.17 tpy in the SOB.

*The draft permit does have an emission factor that is used to determine compliance with the alleged synthetic minor cap for HAPs. It is 2.63E-05. Draft permit, Appendix page 2 or 3. The draft permit claims that CFB1 and 2 have heat inputs of 3000 MMBtu/hr. This is incorrect in that CFB2 is designed to be larger than CFB1 as evidenced by the higher hourly emission limits for CFB2. In any event, even using these non-conservative heat input values, the PTE for CFB1 and 2 for lead is 0.691164 tpy. (2.63E-05 lbs per MMBtu * 3000 MMBtu per hour * 2 boilers * 8760 hrs per year! 2000 lbs per ton = 0.691164). See a/so SOB at Appendix B, Lead PTE is 0.344925 tpy per unit. This is above the 0.6 tpy significant level.[114] Therefore, EKPC is required to submit lead BACT analysis. DAQ should withdraw its completeness determination for the application until EKPC submits a complete lead BACT analysis. DAQ should then hold a new public comment period before deciding on whether to issue the permit.*

Division's Response to Comment IV-D-2:
The Division does not concur. Lead emissions are 0.17 tons per year which is below the PSD applicability threshold of 0.6 tons per year. Therefore PSD and BACT do not apply to lead for this project.

Comment IV-E:

> *E. THE DAQ ERRONEOUSLY REJECTED THE USE OF CLEAN FUELS AS BACT FOR SO2 AND SULFURIC ACID MIST.*
>
> *It is well established that an applicant and permitting authority must determine whether lower pollution rates are achievable by switching to a cleaner fuel. If so, and absent rejection based on site specific collateral impacts. BACT must be established based on clean fuels.*
>
> *Sulfur dioxide emissions from power plants like Smith originate as sulfur in the feedstock, such as the coal or coal waste. Some of the sulfur content in the coal is removed prior to the boiler, some is removed in the boiler, and some is converted to sulfur trioxide. However, most of the sulfur in the coal or coal waste is transformed into S02 in the boiler. As the sulfur content of the feedstock decreases, so too do the emissions of SO2. Therefore, when attempting to control S02 emissions from a coal-fired power plant, the place to start is where S02 originates, the sulfur in the feedstock.*
>
> *Indeed, Congress specifically defined BACT to require consideration of less-polluting fuels as a way to reduce emissions. 42 U.S.C. § 7479(3) (defining BACT as the "maximum degree of reduction achievable . . . through clean fuels). The legislative history of the clean Air Act intended to create a preference for lower polluting fuels. The 1990 Clean Air Act Amendments revised section 169(3) to expressly require "clean fuels" as a pollution control option that permitting agencies must consider when determining BACT. Pub. L. No. 549 § 403(d), 104 Stat. 2399, 2631-32. EPA's contemporaneous interpretation of this amendment was that the "clean fuels" requirement in the definition of BACT codifies the policy "that clean fuels are an available means of reducing emissions to be considered along with other approaches in identifying BACT level controls." Letter from William Rosenberg, U.S. EPA Assistant Adm'r for Air and Radiation to Henry A. Waxman, Chair, Subcommittee on Health and Environment (Oct. 17, 1990), reprinted in 136 Cong. Rec. at S-16916-17.*
>
> *The Environmental Appeals Board has continually reinforced the idea that a permitting agency must consider clean fuels when establishing BACT limits:*
>
>> *The phrase "clean fuels" was added to the definition of BACT in the 1990 Clean Air Act amendments. EPA described the amendment to add "clean fuels" to the definition of BACT at the time the Act was passed, "as . . .*

codifying its present practice, which holds that <u>clean fuels are an available means of reducing emissions to be considered along with other approaches to identifying BACT level controls."</u> EPA policy with regard to BACT has for a long time required that the permit writer examine the inherent cleanliness of the fuel.

In re Inter-Power of New York, 5 E.A.D. 130, 134 (EAB 1994) (emphasis added and internal citations omitted); In re Knauf Fiber Glass, GmbH, 8 E.A.D. 121, 136 (EAB 1999); In re Old Dominion Electric Cooperative, 3 E.A.D. 779, 794 n.39 (EAB 1992) ("BACT analysis should include consideration of cleaner forms of the fuel proposed by the source."); Hibbing Taconite Co., 2 E.A.D. 838, 842-43, PSD Appeal No. 87-3, Slip Op. 9 (EAB 1989) (remanding a permit because the permitting agency failed to consider burning natural gas as a viable pollution control technology). The United States Court of Appeals for the Ninth Circuit similarly held, in Hawaiian Electric Co., Inc. V. EPA, 723 F.2d 1440 (9th Cir. 1984), that low sulfur fuel could be selected as BACT for a facility proposing to burn high sulfur fuel. Id. at 1442

The BACT determination for the CFBs at the Smith Facility failed to adequately explain why it rejected low sulfur coal and completely failed to consider use of biofuels, such as switchgrass, as BACT that would reduce SO2 emissions. This is inadequate under the law.

<u>Division's Response to Comment IV-E:</u>
The Division does not concur. With respect to low sulfur coal, please see the Division's Response to Comment IV-E1. With respect to switchgrass, please see the Division's Response to Comment IV-E2:

<u>Comment IV-E1:</u>

1. THE DAQ ERRONEOUSLY REJECTED THE USE OF LOW SULFUR COAL AS BACT FOR SO2.

EKPC and the DAQ failed to provide an adequate explanation for rejecting low sulfur coal as not economically viable in a top-down BACT analysis. The DAQ's Statement of Basis ("SOB") calculated the cost of using low sulfur Powder River Basin coal as between $39,425 and $41,250 per additional ton of sulfur dioxide ("SO2") removed. Permit Statement of Basis (Dec. 21, 2009) ("SOB") at 25. Based on the additional cost for each ton of SO2 controlled for the low sulfur coal compared to the design basis coal, the DAQ concluded in its SOB that "use of low sulfur coal is not cost effective." SOB at 26. Unfortunately, the DAQ's analysis contained fundamental errors that the EPA has found violate the Clean Air Act. See EPA, Order Denying in Part and Granting in Part Petition for Objection to Permit, In Re: East Kentucky Power Cooperative, Inc., Hugh L. Spurlock Generating Station (Aug. 30, 2007) (attached as Exhibit IV.E.1).

To determine a BACT emission limit, a 5-step, top-down process is utilized for each PSD-regulated pollutant: (1) identify all potentially applicable control options (2) eliminate technically infeasible control options; (3) rank remaining technologies by control effectiveness; (4) eliminate control options from the top down based on energy, environmental, and economic impacts; and (5) select the most effective option not eliminated as BACT. See In re Prairie State Generating Co., 13 E.A.D. —, PSD Appeal No. 05-05, slip op. at 14-18 (EAB Aug. 24, 2006) (summarizing and describing steps in the top-down BACT analysis). Accord In re Three Mountain Power, L.L.C, 10 E.A.D. 39, 42-43 n.3 (LAB 2001); In re KnaufFiberG/ass, GmbH, 8 E.A.D. 121, 129-31 (EAB 1999); and In re Hawaii Electric Light Co., 8 E.A.D. 66, 84 (EAB 1998). In this case, EKPC and the DAQ used this 5-step, top- down process to determine the BACT emission limits, including the sulfur dioxide ("SO2") limit, contained in the permit for the new Smith Units. See SOB at 24-28.

Using the 5-step, top-down process for determining the SO2 BACT emission limits, at step one EKPC identified the use of three potential types of coal for use as fuel in the new Smith Units and examined the potential for controlling S02 emissions: high-sulfur coal (Design Basis "DB" coal), washed coal, and low sulfur Powder River Basin ("PRB") coal. SOB at 25. None of these three coal options were eliminated as technically infeasible at step two. Id.

In accordance with step three of the BACT analysis, EKPC and the DAQ provided information regarding the SO2 potential for the each of three coal types: 0.80 lb/MMBtu for PRB coal, 1.6 for washed coal, and 7.5 for DB coal. Id. In step four, EKPC and the DAQ provided an economic analysis of the SO2 control achieved with each coal, including total, average, and incremental costs. In examining the control costs of the various coals considered, the analysis provides the following:

Table 0-1 Coal Switching Cost Comparison (Controlled)

Coal Characteristic	EKPC Design	Washed Coal	PRB Coal
HHV, Btu/lb	8000	12500	8800
Sulfur Content, percent	3	1	0.35
SO_2, lb/MMBtu, uncontrolled	7.50	1.60	0.80
SO_2, lb/MMBtu, 99 percent controlled	0.075	0.016	0.008
Coal usage, tons/year	1,642,500	1,051,200	1,493,182
Cost per ton delivered	$37.49	$89.00	$64.50
Annual Cost	$61,577,325	$93,556,800	$96,310,227
SO_2, tons/year, uncontrolled	98550	21024	10452
SO_2, tons/year, controlled	985.5	210.24	105

Difference in Cost	baseline	$31,979,475	$34,732,902
Difference in SO_2 emitted	baseline	-775.26	-880.98
Cost per ton of SO_2 removed compared to baseline		$41,250	$39,425

SOB at 25. The DAQ compared the cost of fuel switching (one step) with the reductions achieved by a three-step control regime that includes fuel, limestone addition to the CFB bed, and dry scrubbing. Specifically, EKPC determined that using low sulfur, PRB coal, instead of DB coal, in addition to the cost of the entire pollution control train, would increase total fuel costs by *approximately $34 million and would cost $39,425 more per ton of additional SO2 control. Id.; see also SOB at 26 ("at a cost of $39,425 - $41,250 per ton of SO2 removed, the Division concurs that the use of low sulfur coals are not cost effective"). EKPC and the DAQ then found that "the use of low sulfur coals are not cost effective," and eliminated them as a control option. SOB at 26. This analysis was done "based upon an assumption of a control effectiveness of 99 percent." Id.*

The DAQ then went on to show how the results "would have been substantially different" "if no control options had been assumed." SOB at 26.

Table 0-2 Coal Switching Cost Comparison (Uncontrolled)

Coal Characteristic	EKPC Design	Washed Coal	PRB Coal
HHV, Btu/lb	8000	12500	8800
Sulfur Content, percent	3	1	0.35
SO_2, lb/MMBtu, uncontrolled	7.50	1.60	0.80
Coal usage, tons/year	1,642,500	1,051,200	1,493,182
Cost per ton delivered	$37.49	$89.00	$64.50
Annual Cost	$61,577,325	$93,556,800	$96,310,227
SO_2, tons/year, uncontrolled	98550	21024	10452
Difference in Cost	baseline	$31,979,475	$34,732,902
Difference in SO_2 emitted	baseline	-77526	-88098
Cost per ton of SO_2 removed compared to baseline	baseline	$412.50	$394.25

The DAQ found that EKPC determined that using low sulfur, PRB coal instead of DB coal would increase total fuel costs by approximately $34 million and would cost $394.25 more per ton of additional SO2 control. Id.; see also Id. (the uncontrolled cost is $394 - $413 per ton of SO2 removed). The DAQ found that while this "is cost effective," it is only cost effective "in the absence of the SO? control methods proposed by EKPC." Id. "With the control methods proposed by EKPC, fuel switching is not cost effective." Id.

First, the DAQ's analysis is inconsistent with the applicable law and inconsistent with a prior EPA decision that addressed a very similar situation. For the Spurlock 4 PSD permit, EKPC and the DAQ had done the exact same economic analysis that it did for this action and the EPA found that this analysis violated the law. See EPA, Order Denying in Part and Granting in Part Petition for Objection to Permit, In Re: East Kentucky Power Cooperative, Inc., Hugh L. Spurlock Generating Station at p. 29 - 32 (Aug. 30, 2007) (attached as Exhibit lV.E.1). In that case, the EPA stated:

> *EKPC's BACT selection in this instance is deficient because the analysis does not demonstrate that use of low sulfur eastern bituminous coal is not achievable for this source considering technical feasibility or economic, environmental, or energy impacts. lndeck-Elwood, slip op. at 77 (citing Knauf Fiber Glass, 8 E.A.D. 121, 130 (EAB 1999). Since EKPC's analysis shows that low sulfur eastern bituminous coal has a lower SO2 potential than the DB coal (1 .23 compared with 9), EKPC must provide a basis for excluding that option as a BACT and selecting a less stringent emission limit associated with the DB coal. EKPC's Supplemental BACT analysis does not sufficiently, address the economic, environmental, or energy impacts of using low sulfur eastern bituminous coal. See id. at 7-8 . While EKPC determined that the design coal was "the most economical", this does not demonstrate that use of low sulfur eastern bituminous coal is economically infeasible for this source. See, e.g., Masonite Corp., 5 E.A.D. 551, 564 (EAB 1994) (Determining whether use of a technology is cost effective usually involves a comparison of the control option's cost-effectiveness "with what other companies in the same industry have been required to pay in recent BACT determinations to remove a ton of the same pollutant. In most cases, a control option is determined to be economically achievable if its cost-effectiveness is within the range of costs being borne by other sources of the same type to control the pollutant.") (citing Inter-Power of New York, 5 E.A.D. at 135).*
>
> *Accordingly, the Administrator is granting this petition with respect to the issue of low sulfur coal and remanding the permit to KYDAQ and EKPC for further explanation and/or analysis regarding the choice of the design basis coal as BACT for SO2 and, if necessary after such analysis, for adjustment of the SO2 limit to appropriately reflect BACT. See Indeck-E/wood, slip op at 83 (remanding a specific BACT determination to the permitting authority after finding the record did not provide a sufficient explanation for the decision making process used to set the emission limit).*

See EPA, Order Denying in Part and Granting in Part Petition for Objection to Permit, /n Re: East Kentucky Power Cooperative, Inc, Hugh L. Spurlock Generating Station at p. 32 (Aug. 30, 2007) (attached as Exhibit IV.E.1).

The SO2 BACT analysis in this case suffers from the same fatal flaw as the SQ BACT analysis in Spurlock 4. The only thing that EKPC and the DAQ did was determine that the design coal was "the most economical." However, the agency must do more than that to eliminate lower sulfur coal as a control technology. For instance, the DAQ should have compared control option's cost-effectiveness "with what other companies in the same industry have been required to pay in recent BACT determinations to remove a ton of the same pollutant." See Id.; see a/so Masonite Corp., 5 E.A.D. 551, 564 (EAB 1994) (Determining whether use of a technology is cost effective usually involves a comparison of the control option's cost-effectiveness "with what other companies in the same industry have been required to pay in recent BACT determinations to remove a ton of the same pollutant. In most cases, a control option is determined to be economically achievable if its cost- effectiveness is within the range of costs being borne by other sources of the same type to control the pollutant.") (citing Inter-Power of New York, 5 E.A.D. at 135); NSR Manual, p. B.44 (The NSR Manual elaborates that: "if the cost of reducing emissions with the top control alternative, expressed in dollars per ton, is on the same order as the cost previously borne by other sources of the same type in applying that control alternative, the alternative should initially be considered economically achievable, and therefore acceptable as BACT.") There was no attempt by the DAQ to compare the cost of using low sulfur coal at other boilers with the cost at Smith.

Second, the DAQ's SOB uses an analysis it terms "cost comparison" or "cost per ton of SO2 removed" to compare the cost of fuel switching to the incremental cost effectiveness of post combustion controls (i.e., various types of dry scrubbers and sorbent injection). This is an apples-to oranges comparison. This method is not a recognized economic feasibility metric because it distorts cost effectiveness and substantially penalizes low sulfur fuel by including S02 emission reductions achieved by other control options [limestone addition and scrubbing] while excluding the relative costs of these other controls. The cost comparisons must be on an "apples-to-apples" basis. See, e.g., NSR Manual at B.39 (stating that a source that compares costs between options must do so with standard assumptions for all options, discussing an 85% capacity factor in that case). Here, however, the DAQ attempted to compare the fuel costs plus both a limestone CFB and a dry scrubber, rather than a direct comparison of the fuel costs.

When the DAQ performs a legally adequate BACT analysis, including an apples-to-apples comparison of fuel costs, low sulfur coal was not prohibitively expensive. See SOB at 26, Table 5-6. Furthermore, as explained above, the cost analysis should consider the reduction in SAM as well as SO2 from lower sulfur coals. Since the permit record contains no evidence that low sulfur coal is otherwise infeasible for this source (i.e., based on energy, economic, or factors other than cost), BAG for SO2 emissions at the Smith facility will require use of low sulfur coal.

Division's Response to Comment IV-E1:
The Division does not concur. With respect to the reference to the Order Denying in Part and Granting in Part Petition for Objection to Permit, In Re: East Kentucky Power Cooperative, Inc., Hugh L Spurlock Generating Station (Aug. 30, 2007), the commenter incorrectly characterizes the EPA's finding. The Order simply required DAQ to provide more explanation in the Response to Comments.

The use of lower sulfur coal was rejected on the basis that it is a less effective control technology than the control train proposed by EKPC. The use of lower sulfur coal results in potential emission of 10,452 tons of SO2 per year whereas the control technology proposed by EKPC results in 986 tons per year. The applicant proposes the top control alternative and does not need to provide cost and other detailed information in regard to other control options.

It is reasonable to consider whether the use of lower sulfur coal and the control train combined is cost-effective. This necessarily requires an analysis of controlled emissions because it has been already determined that without controls, low sulfur coal should be rejected. The analysis depicted in Table 5-5 of the Statement of Basis demonstrates that neither PRB nor washed coal is cost effective at \$39,425 and \$41,250, respectively per ton of SO_2 removed. This analysis considers only the cost of coal, which is appropriate because considering additional costs would only increase the cost. As a result, the Division determined that these amounts were not cost-effective even without considering additional costs.

The Division does not concur with the statement, "Here, however the DAQ attempted to compare the fuel costs plus both a limestone CFB and a dry scrubber, rather than a direct comparison of fuel costs is incorrect."

With respect to cost comparison to similar sources, EPA Region 8's Response to Public Comments dated August 30, 2007 in the Deseret permit record[1] contains a summary beginning on page 29 of comparisons to similar sources. None of the other decisions contains a finding that \$39,425 or higher per ton of SO_2 removed is cost-effective.

With respect to sulfuric acid mist, there is a potential of 66 tons per year of H_2SO_4 emissions, which is 6.7 percent of SO2 emissions (66/986 x 100 percent). However, the result was not cost effective; therefore, the Division does not concur that it would not be necessary to consider reductions in SAM.

Comment IV-E2:

> *2. THE DAQ ERRONEOUSLY REJECTED THE USE OF BIOFUELS AS BACT FOR SO2.*
>
> *During the 5-step, top-down process for determining the SO2 BACT emission limits, at step one EKPC identified the use of three potential types of coal for use as fuel in the new Smith Units and examined the potential for controlling SO2 emissions: high-sulfur coal (DB coal), washed coal, and low sulfur Powder River*

[1] http://www.epa.gov/Region8/air/permitting/deseret.html

Basin ("PRB") coal. SOB at 25. EKPC did not identify the use of biofuels, such as switchgrass, as a potential control option. Id.

EKPC and DAQ should have identified the use of biofuels during this top-down analysis because use of this cleaner fuel option is an available technology for the Smith Facility. In its Response to Data Requests, EKPC stated the following:

> *Two of Spurlock Station's generating units feature circulating fluidized bed technology that allow them to burn a wide range of fuels, such as bioniass, including swithgrass and wood. EKPC's Smith CFB#1 at the Smith Station in Clark County will also feature this technology.*
>
> *EKPC is part of a four-year pilot project with the University of Kentucky's College of Agriculture and local farmers. The pilot study is evaluating the feasibility of using switchgrass, which is native to Kentucky, as a fuel for power plants. This pilot project has potential to grow in regards to tons produced and length of project term. In December 2008, EKPC mixed about 70 tons of processed switchgrass into the coal feedstock of the first clean- coal unit built at Spurlock Station, Gilbert Unit 3. In late 2009, EKPC is planning to conduct another test with approximately 300 tons of switchgrass.*
>
> *EKPC has commissioned a fuel study to be conducted by an independent consultant, Liberty Green Renewable, to study the supply and demand of woody biomass for the CFB units at Spurlock Station. The intent of this study is to determine the availability of, and cost for, delivery of woody biomass to Spurlock to meet a portion of its annual fuel needs.*

See EKPC Response to Public Interest Groups' First Data Request at Response to Request #46 at pages 57-58 (attached as Exhibit lV.E.2); see a/so, EKPC Supplemental Response to Public Interest Groups' First Data Request #19 (attached as Exhibit IV.E.3). Thus, the CFBs unquestionably could burn biofuels, such as swithgrass.

Despite the availability of this control option, EKPC and DAQ did not identify this as a BACT control option to control S02 emissions. SOB at 25. If the CFBs were to burn 100% biofuels it should reduce SO2 emissions from these units. Moreover, if they CFBs were to burn biofuels anywhere from 1 to 100% of its feedstock, it would proportionately reduce SO2 emissions. Failure to consider this clean fuel option is a violation of the Clean Air Act. See, e.g., In The Matter of Cash Creek Generation, LLC, Petition Nos. IV-2008-1 & IV- 2008-2, at p. 9 (Dec. 15, 2009) (attached as Exhibit lV.E.4) (DAQ violated the Clean Air Act because it failed to consider the possibility of natural gas as an alternative primary fuel source to syngas, when the facility is capable of burning both gases and the agency was required, in its BACT analysis, to consider all possible primary fuel types.); 42 U.S.C. § 7479(3); Inter-Power of New York, 5 E.A.D. at 134; Knauf

Fiber Glass, B E.A.D. at 136; In re Old Dominion Electric Cooperative, 3 E.A.D. at 794 n.39; Hibbing Taconite Cc., 2 E.A.D. at 842-43; Hawaiian Electric Co., Inc. v. EPA, 723 F.2d 1440, 1442 (9th Cir. 1984); EPA, Order Denying in Part and Granting in Part Petition for Objection to Permit, In Re: East Kentucky Power Cooperative, Inc, Hugh L. Spurlock Generating Station at p. 32 (Aug. 30, 2007) (attached as Exhibit IV.E.1).

Furthermore, we note that the top choice BACT limit is based on burning what is mainly waste coal. At 40% ash, 3% sulfur, 10% moisture and only 8000 btu per Ib, the design fuel must be mainly waste coal. See SOB at 17. However, EKPC told the Kentucky PSC that it would primarily use Kentucky bituminous coal. See Lx. IV.E.5 at Ex. 3, page 1. EKPC told the PSC that waste coal only may be used. Id. at 2. Thus, BACT that would require only low sulfur, low ash Kentucky bituminous coal and no waste coal would not redefine the source. Rather it would be consistent with EKPC "primary" business plan. Furthermore, it seems highly inappropriate for DAQ to base the BACT determination on a condition that is not consistent with what EKPC told another part of the Energy and Environment Cabinet, that is the Public Service Commission.

Division's Response to Comment IV-E2:
The Division does not concur. As noted in the comment, the "pilot study is evaluating the feasibility of using switchgrass…"; therefore, it cannot be claimed that switchgrass is feasible. Switchgrass is not available in the quantities that would be necessary for the Smith CFBs to operate.

All emission limitations in the permit issued by the Division are enforceable as a practical matter regardless of the fuel type.

F. COOLING TOWERS
1. THE COOLING TOWERS DO NOT HAVE A VOC BAG LIMIT

There is no VOC BACT limit or analysis for the cooling towers. Cooling towers can have VOC emissions if organic substances are used to treat the cooling water. Therefore, DAQ must conduct a BACT analysis for VOCs for the cooling towers and allow the public the opportunity to review the BACT analysis and comment on it before DAQ issues the final permit.

Division's Response to Comment IV-F1:
The Division does not concur. The commenter has provided no support for their claim.

Comment IV-F2:
2. THE APPLICATION FAILED TO CONSIDER DRY COOLING AS BACT FOR PM, PM1O, PM2.5 and VOCs
Dry cooling, or air condenser cooling, is a mature technology that has been used on power plants for decades. The Basin Electric Power Cooperative's Dry Fork coal fired plant is being built with dry cooling. Ex. IV- B-i-i at 5; See also

http://www.basinelectric.com/Projects/DryForkStation/index.html#Projectfacts . There is also a wood-fired CFB proposed for Eastern Kentucky that is proposing to use dry cooling. The documentation of this proposed facility is in DAQ's files and is hereby incorporated by reference. Thus, dry cooling is a control technology for PMIPM1OIPM2.5 and VOC emissions from the cooling towers that DAQ and EKPC completely failed to consider. It is also technical feasible. See e.g. Ex. IV-B-1-]. at 5; See also httn://www,basinelectric.com/Proiects/Drv Fork Station/index.html#Proiectfa cts. Thus, DAQ must consider it as the top control technology in a new BACT analysis. To reject it, DAQ must not find that it has cost, environment, or energy impacts but that these impacts are significantly different than impacts than at other facilities. DAQ seems to somewhat acknowledge that this is the standard. See SOB at 22.

Division's Response to Comment IV-F2:
The Division does not concur. The Division did not "somewhat acknowledge that this is the standard" on page 22 of the Statement of Basis. The standard is articulated on page 16 of the Statement of the Basis by quoting the definition of BACT in 401 KAR 51:001, Section 1.

Two differences exist between the emissions from dry cooling towers and wet cooling towers. The most obvious is that pollutants dissolved in the water of a wet cooling tower become airborne when evaporation occurs. The other is that approximately 0.5 percent of the electricity created by a power plant with a wet cooling tower is needed to operate the cooling system, whereas approximately 1.5 percent of the electricity created by a power plant with a dry cooling tower is needed to operate its cooling system.[2] Therefore, the difference in emissions resulting from a dry cooling tower will be dominated by the increase in emission resulting from burning an extra one percent of the plant's coal capacity, which greatly exceeds the reduction in emissions from not evaporating any cooling water. The two cooling towers as designed would emit 6.40 tons of particulate matter per year, whereas the energy penalty of dry cooling towers would result in over 20 tons of SO2 alone. In terms of total emissions increases, dry cooling towers are not the "top control technology".

Comment IV-G:

G. EMERGENCY GENERATOR(S) AND FIREWATER PUMP(S)

The draft permit fails to contain enforceable BACT limits for all pollutants for the emergency generator(s) and/or firewater pump(s). It must.

Division's Response to Comment IV-G:
Please See the Division's Response to Comment I-A.

Comment IV-H:

H. PM10/PM2.5 FOR THE CFBs

2 http://www.world-nuclear.org/info/cooling_power_plants_inf121.html

The SOB fails to include a BAG analysis for PM2.5 from the CFBs, although it does mention that SO2 controls will also reduce PM emissions. The SOB must have a separate and complete discussion of BACT for PM2.5. A BACT analysis for PM2.5 differs from a BACT analysis for PM10. See Ex. lV-H1. The PM2.5 BACT should have wet ESP as the top control technology choice. See Id. As explained in the PM2.5 Modeling section, DAQ has not shown that the use of PM10 as a surrogate for PM2.5 is appropriate in this case.

Furthermore, the draft permit does not contain an adequate BACT limit. The draft permit limits total PM10/PM2.5 to 0.012 lb/MMBtu and to 0.009 lb/MMBtu filterable based on a 24-hour averaging time. The SOB does not explain where this emission rate came from. A proper BACT analysis requires consider of the range of control levels a particular control technology can achieve as well as consideration of various control methods. The SOB fails to do this. The draft permit also fails to say whether this is a rolling or block average. The draft permit also fails to contain a BACT emission limit for total PM10/PM2.5 during startup, shutdown, and malfunction.

BACT is 0.0088 lb/MMBtu for total PM emissions based on a three hour block average. Pennsylvania issued a PSD permit in April 1995 to the Northampton Generating Company with a total PM1O limit of 0.0088 lb/MMBtu. This facility burns anthracite Cuim in a 1,146 MMBtu/hr circulating fluidized bed boiler. Compliance testing in February 2001 reported total PM1O emissions of 0.0045 lb/MMBtu. The permit limit and the compliance tests for Northampton have been rejected by other permitting agencies in the past due to those agencies' confusion as to whether the 0.0088 lb/MMBtu Northampton permit limit includes condensable PM. The confusion appears to stem from the fact that the Northampton permit requires testing by "Method 5." USEPA Method 5 tests only for filterable particulate matter. However, the "Method 5" referred to in the Pennsylvania DEQ Permit for Northampton refers to Pennsylvania Method 5, which includes both front half and some condensable (backhalf) emissions (i.e., both filterable and condensable PM). The Pennsylvania permit and compliance tests for Northampton included condensable fraction PM in the back half of the control train. Id.

A test of the JEA facility, conducted by Black & Veatch for the Department of Energy, measured filterable PM emissions of 0.004 lb/MMBtu. This is significantly lower than the proposed 0.012 lb/MMBtu for total PM 10/PM2.5 for the Smith CFBs. The fact that the power plants are not exactly the same does not, by itself, justify the rejection of a BACT limit. The SOB offers no basis for the rejection of these lower BACT limits.

<u>Division's Response to Comment IV-H:</u>
The Division does not concur with respect to "*the draft permit does not contain an adequate BACT limit*". As discussed in the Statement of Basis, the Division attempted to discover if better PM removal efficiencies were available and failed to do so. The commenter has provided no evidence to the contrary.

With respect to "*where this emission rate came from*", the calculation is discussed on pdf page 395 of commenters Ex. I (which is a copy of the draft permit package), as follows:

(0.005 grains/dscf) x (1 lb/ 7000 grains) x (1 min/597513 dscf) ÷ (3000 MMBtu/hr) x (1 hr/60 min) = 0.0085359 lbs/MMBtu

0.005 grains/dscf is the outlet grain loading of the fabric filter proposed as BACT. 597513 dscf is the flow rate.

Comparisons to other permit limits are irrelevant since the best technology was selected as BACT. The fact that other units may have different results is illustrated by the above equation, which shows that different equipment parameters, such as flow rate in relation to heat input, will result in different answers.

Also, please refer to the Division's response to Comment III-A.

Comment V:

V. THE DRAFT PERMIT SHOULD BE DENIED BECAUSE CLEANER, MORE COST EFFECTIVE ALTERNATIVES TO THE PROPOSED PLANT EXIST.

DAQ should not finalize the Draft Permit because cleaner alternatives that are less risky and less costly than the Proposed Plant are feasible now. The Proposed Plant poses numerous harms to the environment, including emission of criteria air pollutants and millions of tons per year of greenhouse gases. In order to fully consider the alternatives, DAQ first needs to fully consider the impacts from the proposed CFBs. Exhibits V-25 to V-72 as well as the testimony at the public hearing of Cherise Williams, Dallas Ratliff, Fr. John Rausch, Erica Urias, Jeff Chapman-Crane, and Sierra Emrich, which we incorporate herein by reference, provide a good overview of the impacts that the CFBs will cause. Again, it is only by considering and understanding these impacts that DAQ can fully consider the alternatives to the proposed CFBs.

Section 165(a)(2) of the Clean Air Act requires as part of the permitting for a proposed major source that the public be provided the opportunity to submit testimony on the "air quality impacts of such source, alternatives thereto, control technology requirements, and other appropriate considerations." 42 U.S.C. § 7475(a)(2) (emphasis added). As the agency is required to respond to comments submitted by the public, DAQ must substantively address the alternatives issues raised in these and other public comments. In addition, this language has long been interpreted to grant a permitting authority broad discretion to, at its own initiative, evaluate need, consider alternatives (including the "no build" alternative), conduct or require additional analyses, and impose permit conditions beyond the baseline requirements of BACT in order to protect air quality. In re Prairie State Generating Co., PSD Appeal No. 05-05, slip op. at 40 (E.A.B. 2006), quoting U.S. EPA Draft NSR Manual, 1990 ("NSR Manual"), at 8.13.

Division's Response to Comment V:
The Division does not concur. The Division's interpretation of the Clean Air Act Section 165(a)(2) is consistent with EPA's interpretation on this Section. As discussed in *In re Prairie State Generating Co.* beginning on page 39:

> *"The obligation to consider "alternatives" under section 165(a)(2) is not unlimited, as OAR correctly notes. See OAR Brief at 17-18. First, it is self-evident that Congress did not intend section 165(a)(2)'s reference to "alternatives" to open the public comment process to matters unrelated to air quality. Thus, as stated by OAR, the "permitting authority need not respond to comments on alternatives that commenters recommend to achieve objectives unrelated to air quality." OAR's Brief at 18. It is sufficient for the permitting authority to merely explain that the comment falls outside the scope of what the public is entitled to raise during the public comment period. We also agree with OAR's statement that the permitting authority is not required to "conduct an independent analysis of available alternatives." Id. at 17. Because the CAA contains specific language for permits in nonattainment areas requiring the permit issuer to perform an analysis of alternative sites, sizes, and production processes, among other things, to determine whether the benefits of the proposed source outweigh its costs, and because similar specific language is not included for the issuance of a PSD permit, compare 42 U.S.C.§ 7503(a)(5) with id. § 7475(a), the PSD permit issuer therefore is not required to perform an independent analysis of alternatives. For this reason, we find no clear error in IEPA's response to comments that the statutory language does not "require" a permitting authority to conduct an alternatives analysis, nor in IEPA's response to comments that "it cannot be assumed that Congress intended that a wide-ranging analysis of alternatives must be conducted by the permitting authority." Response to Comments at 13-14.*
>
> *OAR also correctly states that in the PSD context "[t]he extent of [the permitting authority's] consideration and analysis of alternatives need be no broader than the analysis supplied in public comments." OAR's Brief at 17. This conclusion flows naturally from our conclusion that Congress did not require the PSD permit issuer to undertake an independent investigation of alternatives. Indeed, more generally, the permitting regulations do not require the permit issuer's response to public comments "to be of the same length or level of detail as the comment." In re NE Hub Partners, 7 E.A.D. 561, 583 (EAB 1998). Instead, "[t]he response to comments document must demonstrate that all significant comments were considered." Id.; see also 40 C.F.R.§ 124.17(a)(2)."*

Similarly, page B.13 of the NSR manual states in part:

> *Historically, EPA has not considered the BACT requirement as a means to redefine the design of the source when considering available control alternatives. For example, applicants proposing to construct a coal-fired electric generator, have not been required by EPA as part of a BACT analysis to consider building a*

natural gas-fired electric turbine although the turbine may be inherently less polluting per unit product (in this case electricity).

The Division has no authority to require an alternative on the basis that the alternative is "less risky and less costly" than the proposed plant. That authority has been vested in the Public Service Commission pursuant to KRS 278.020, Certificate of convenience and necessity.

With respect to the "numerous harms to the environment", the proposed permit complies with all air quality requirements effective on the date of permit issuance.

<u>Comment V-A:</u>

A. NO-BUILD ALTERNATIVE

DAQ must take into consideration a no-build alternative, as there is no need for the 600 MW total of new generating capacity or the air pollution that it will produce. Recent data from the Energy Information Administration's ("EIA") Electric Power Monthly shows that electricity consumption in Kentucky decreased by 3,634 million kWh or 6% between August 2008 and August 2009.[115] Further, demand for electricity from coal is down in Kentucky. According to EIA's Electric Power Monthly, consumption of coal for electricity has decreased 4.4% in the year from August 2008 and August 2009.[116]

More specifically, EKPC's forecast of how much electricity it needs is flawed, resulting in EKPC planning to add supply-side fossil fuel resources that it does not need. Our comments below address the total amount of electricity needed, sometimes referred to as total requirement, which is measured in megawatt-hours or gigawatt-hours. Demand or peak needs, which is measured in megawatts, is something different. Although EKPC often conflates the two, for example, discussing its peak demand when addressing the need for base load supply-side resources, the two concepts are distinct although they can be interrelated.

Historically, EKPC has over-estimated its energy needs. Overestimation of energy needs results in spending more capital than necessary, causing rates to have to go up to pay for unused or under-utilized power plants.

EKPC's 2009 IRP demonstrates EKPC's historic over-estimation of energy needs. See Ex. V-2, EKPC 2009 IRP. For example, page 5-5 of the 2009 IRP shows that EKPC's forecast for its energy requirements in 2020 decreased between 2004 and 2008 by 2,273,498 MWh per year, or almost 12%. This is about as much energy as EKPC could hope for from Smith 1. Notice also that the amount of electricity EKPC has over-estimated trends upward as a percentage over time and that the over-estimation is consistent. See Ex. V-2, EKPC 2009 IRP, at 5-5.

The 2009 IRP's forecast is unrealistic because it is based on outdated data. EKPC admits that it conducted no load forecast since August 2008 even though EKPC did not file the 2009 IRP until April 21, 2009. See Public Interest Groups' First Data Request, Response 7, available at (http://psc.ky.gov/pscscf/2009%20cases/2009- 00106/20090807_EKPCs Responses to 1st Data Request of Public Interests Group.PDF). We are in a period of dramatic change for the electric industry because of a number of factors including the economic recession, the declining availability of cheap fossil fuels, the increased attention to climate change, the advancement of knowledge of health impacts from pollution, and the decrease in costs and increase in availability of renewable energy technologies. In the current situation, using load forecasts that are over seven months old leads to unreliable results in resource planning.

EKPC's most recent forecast was substantially wrong for the first year in the forecast, that is 2009. This means that it will have a dramatic effect on energy requirements for later years in the IRP because of the lack of compounding. EKPC's actual total requirement for 2008 was 12,948,091 MWh. Ex. V-2, EKPC 2009 IRP, at 7-2. The 2009 IRP predicts that the total requirement for 2009 will be 13,647,057 MWh. This represents a predicted 5.4% increase in total requirements between 2008 and 2009. However, looking at the 2009 data that EKPC has supplied for actual energy requirements, thus far EKPC has experienced a 5.8% decrease in total energy requirements. See Public Interest Groups' First Data Request, Response 13. This calls into serious question the IRP's plan for future base load generating resources. Therefore, any attempt by the DAQ to defer to the IRP would be inappropriate. As to the Certificate of Public Convenience and Necessity ("Certificate"), currently pending before the PSC is a case challenging the continued validity of the Certificate. Therefore the DAQ would need to wait until that case reaches final resolution before assigning any value to the Certificate.

There are additional reasons to think that the 2009 IRP projection of future energy requirements are significant over-estimations. EKPC's load forecast fails to consider mandatory improvements in the efficiency of various appliances, including such large energy users as supermarket refrigeration, commercial HVAC systems and small electric motors. See Environmental Groups's Second Data Request, Response 83, Table 1 available at (http://psc.ky.gov/pscscf/2009%20cases/2009- 00106/20090821 FAX Public Interests Groups 2nd Set of Data Requests to EKPC.PDF). Furthermore, EKPC does not include future efficiency savings from small commercial class. See Id. at 3-4. EKPC's future energy and load projections should consider all required improvements in efficiency.

Furthermore, EKPC's analysis of one of its largest users appears to be largely based on guess work. EKPC admits that it does not consider the overall steel market in trying to predict Gallatin Steel's energy use. See Environmental

Groups' Second Data Request, Response 85. Even for the factors that EKPC does consider, it makes a "qualitative determination." Before investing billions of dollars in future supply-side resources, EKPC has to make an objective analysis based on data. There are obviously professionals that track the steel market. EKCP should get some professional help to make these sorts of judgments in the future.

<u>Division's Response to Comment V-A:</u>
The Division does not concur. See the Division's Response to Comment V.

<u>Comment V-B:</u>

B. ENERGY EFFICIENCY

EKPC could meet electricity demands by increasing energy efficiency and utilizing renewable sources of energy. The PSC has previously stated the need for EKPC to more aggressively pursue energy efficiency options. When the PSC granted Licking Valley RECC, a member of EKPC, a rate increase the order stated:

> *The Commission believes that conservation, energy efficiency and demand-side management will become more important and cost- effective as there will likely be more constraints placed upon utilities whose main source of supply is coal-based generation. The Governor's proposed energy plan, Intelligent Energy Choices for Kentucky's Future, November 2008, calls for an increase in demand-side management by 2025. In addition, the Commission stated its support for cost-effective demand-side programs in response to several recommendations included in Electric Utility Regulation and Energy Policy in Kentucky, the report the Commission submitted in july 2008 to the Kentucky General Assembly pursuant to Section 50 of the 2007 Energy Act. Although Licking Valley has a number of energy efficiency programs in place, the Commission believes that it is appropriate to encourage Licking Valley, and all other electric energy providers, to make a greater effort to offer cost-effective demand-side management and other energy efficiency programs.*

Ex. V-3, KY PSC Order Case 2009-0016 (Dec. 11, 2009), 4. The Midwest Energy Efficiency Alliance (MEEA) study Midwest Residential Market Assessment and DSM Potential Study confirms that Kentucky has great technical potential for energy efficiency that has yet to be tapped. Ex. V-4, Midwest Energy Efficiency Alliance, Midwest Residential Market Assessment and DSM Potential Study, Table 5-15, p. 62. There are a variety of energy efficiency programs that EKPC could use that are much more cost-effective on a kilowatt-hour basis than increasing base load generation capacity. This is illustrated in the table below.

Energy Efficiency Programs Recommended for

East Kentucky Power Cooperative"[117]

Program Name	Cost of Saved Energy ($/kWh)	Measure Lifetime	Cumulative Lifetime Energy Savings (MWh)	Program Year 10 Cumulative Annual Energy Savings (MWh)	Cumulative Annual Summer Demand Savings (MW)	Cumulative Annual Winter Demand Savings (MW)
Air Source Heat Pump Retrofit	0.017	20	3,486,000	174,300	9	45
Residential Lighting	0.018	4	240,000	60,000	8	8
Load Control Programmable Thermostat	0.018	10	1,926,000	192,600	140	0
Air Conditioner Exchange	0.058	12	54,000	4,500	7.4	0
Residential Water Heater Replacement	0.071	12	223,486	18,624	4.3	4.32
Residential Installment Payment Refrigerators	0.093	15	133,950	8,930	2.6	2.83
Commercial/Industrial Air Conditioner Tune-up	0.015	10	374,100	37,410	33	0
Commercial/Industrial Demand Response	0.025	10	525,000	52,500	175	175
Commercial Energy Efficient Lighting	0.040	10	1,134,000	113,400	22.6	12.24
Industrial Variable Speed Drives	0.018	15	1,033,200	68,880	13.6	7.49
Industrial Energy Efficient Motors	0.028	15	186,000	12,400	2.4	1.30
Portfolio Total			9,315,738	743,544	418	256

Turning to what EKPC calls Demand Side Management, "DSM," the 2009 IRP viewed in isolation is less aggressive than is reasonable, but it is on the right track. The 2009 IRP predicts that after 10 years of implementation, EKPC's DSM program would save 455,519 MWh. Ex. V-2, EKPC 2009 IRP, at 8-51. Sierra Club, KEF and KFTC had experts develop a plan that resulted in 743,544 MWh of annual savings, or 63% more than EKPC's new DSM programs, Id.

EKPC's DSM program could achieve significantly greater energy reductions, even within its current framework. For example, EKPC rejected 72 DSM programs based on subjective analysis. Ex. V-2, EKPC 2009 IRP, Technical Appendix, at DSM-1. Some of these subjective programs are actually cost effective. For example, EKPC rejected a room air conditioner exchange program. Id. at DSM-8. However, the Portfolio found the cost of this program to be 5.8 cents per kilowatt-hour. Ex. V-S at 38. This is probably less than the cost of new generation for EKPC and provides a hedge against future cost increases. In addition, this program would involve giving EKPC customers free air conditioners. It is difficult to see how the program would not be overwhelmingly supported.

EKPC also rejected a program to help customers install low flow showerhead and faucet aerator/pipe insulation. Ex. V-2, EKPC 2009 IRP, Technical Appendix at DSM-1. This program is highly cost effective because it has low capital costs. For example, EKPC could buy faucet aerators at wholesale prices for very little money. The program also helps customers save money on their energy and water bills. The major expense in such a program comes from delivery of the program. However, EKPC plans to go ahead with other programs that could be very cheaply combined with the low flow showerhead /faucet aerator/pipe insulation *program. This includes the low income weatherization, enhanced button up, and tune up programs. Id.*

Thus, EKPC should conduct a quantitative analysis of all 103 programs, including a consideration of the economies of scale that can be achieved by combining programs. In this quantitative analysis, EKPC should have to consider the true cost savings. For example, EKPC admits that it does not consider the cost savings to distribution cooperatives from avoided capital improvements or operation and maintenance costs because of reduced demand and energy requirements from DSM programs. See Public Interest Groups' First Data Request, Response 48. EKPC's analysis should evaluate all cost savings, not just selected ones.

Once EKPC comes up with a comprehensive DSM plan of which programs to include, EKPC must also come up with an effective plan to implement it. For example, Glenn Cannon, an expert on DSM programs for public power entities, says that a utility needs one employee dedicated to DSM from approximately every 5,000 customers it has. Bluegrass Energy has one employee dedicated to DSM and over 50,000 customers. This is a formula for failure. Thus, it is not surprising that EKPC's energy audits and touchtone energy home certifications reported are in the single digits. See, e.g., Supplemental Public Interest Groups Request, Response 19 at page 28 (http://psc.ky.gov/pscscf/2009%20cases/2009-00106/20090828 EKPCs Revised Responses.PDF).

One of the keys to achieving successful reductions in energy requirements through DSM programs is being able to pay for the DSM programs. EKPC said they were going to apply for a DSM surcharge. See Supplemental Public Interest Groups Request, Response 18, pages 29-31. However, EKPC has not made such an application. EKPC should do so or come up with an alternative funding mechanism.

Division's Response to Comment V-B:
The Division does not concur. Please see the Division's Response to Comment V.

Additionally, the Public Service Commission has exclusive jurisdiction over the rates and service of utilities pursuant to KRS 278.040. In particular, KRS 278.285 addresses Demand Side Management programs.

Comment V-C:

C. RENEWABLES

In the report A Portfolio of Energy Efficiency and Renewable Energy Options for East Kentucky Power Cooperative, Zinga and McDonald demonstrate, based on the conditions in EKPC's service area, that EKPC could access "over one million

MWh of power from renewable sources," which is outlined in the chart below. Ex. V-5, at 26.
Renewable Energy Program Recommendations for East Kentucky Power Cooperative"[118]

Renewable Energy Resource	Annual Generation (MWh)	Maximum Demand (MW)	Cost ($/kWh)
Residential Solar Water Heaters	24,530	11	$0.075
Commercial Solar Water Heaters	17,456	7	$0.053
Wind-Powered Generators**	192,720		$0.035
Hydroelectric Power	842,055	191.5	$0.036
TOTAL	1,076,761	209.5	$0.037

The argument that renewables are intermittent sources of power relative to fossil fuels is not entirely accurate as it disregards the reality that fossil fuel power plants have planned and unplanned outages. While the sun does not always shine and the wind does not always blow, all electric generating units, regardless of the fuel, are intermittent to varying degrees.

For example, one huge coalfired power plant in the Midwest had around a 65% availability factor for around a decade after it started up. That means that 35% of the time, if the utility company wanted to turn this coal fired power plant on, they couldn't. In addition, coal-fired power plants have almost gone off-line because they couldn't get enough coal, see Ex. V-6, KCP&L Battling Ice, Frozen Coal to Keep Power Flowing (The coal was frozen) and nuclear plants have almost had to shut down because there wasn't enough water. See Ex. V-7, Water: The nuclear industry's Achilles' heel. However, the utility industry deals with the intermittent nature of fossil fuel plants fairly well and keeps the lights on. Utilities maintain around a 15% reserve margin of generating sources. That means if they have a peak demand of 100 megawatts, the utility will have 115 megawatts of generating capacity. They don't have to own that 115 megawatts of generating capacity. They can enter into agreements with neighboring utilities or merchant power providers to meet their reserve margins.

Solar and wind power plants are also intermittent although mainly for different reasons. Solar and wind power plants break down far less than coal fired power plants. For example many wind turbines have a 95% guaranteed availability rate and actually have a 97% or higher availability factor. There isn't a coal fired power plant maker who would offer a guarantee for a 95% availability factor. However, solar and wind are intermittent because their fuel sources (sun and wind) are intermittent. In one sense, this is an easier problem to deal with because one can predict the wind and sun better than one can predict when a high pressure, high temperature machine is going to break. Our electric generation sources have always been intermittent but utilities have successfully dealt with this challenge. They will continue to do so as we transition to a generation system based more and more upon wind and solar.

EKPC's 2009 IRP is difficult to understand yet clearly indicates a lack of serious commitment to meeting its customers' needs with clean, renewable energy from sources like wind and solar. The 2009 IRP does include a "30MW Biomass PPA" but does not further elaborate. See Ex. V-2, EKPC 2009 IRP, at 8-49. We can extrapolate, although a good IRP would not require such extrapolation, that the Biomass PPA would be coming from a Non-Utility. See Public Interest Groups First Data Request, Response 73 Attachment 1, Corrected Table 8.(4)(b)-1. This Biomass PPA would meet about 1.5% of EKPC's energy requirements in 2023. Id. Biomass is a very broad term that means different things to different people. Some energy sources that are considered biomass are not clean, some are not renewable and some neither. All we know is that at a time when whole states, because of their renewable portfolio standards? will be getting a quarter, a third, or more of their electricity from renewable sources, this Biomass PPA will be contributing a very minor amount to EKPC's energy mix.

In contrast, while not as aggressive as it should be, AEP's IRP does include a significant amount of renewable. See Kentucky Power IRP, Case No. 2009-00339, AEP App. Vol. A, 1-2, available at (http:/psc.ky.gov/pscscf/2009%20cases/2009-00339/20090817 AEP App_Vol A.PDF). This includes meeting 3% of its capacity needs with solar in 2023, 7% with wind and 6% with biomass. Id.

EKPC received over 2,100 MW of interest in renewable even though they asked for only 300 MW. Supplemental Response to Public Interest Groups Request 19 at page 26. Thus, the renewable energy is likely there.

Division's Response to Comment V-C:
The Division acknowledges the comment. It does not appear to be germane to the draft permit, but rather is about EKPC's 2009 IRP. Integrated Resource Plans are filed with the Public Service Commission pursuant to 807 KAR 5:058, Integrated resource planning by electric utilities.

Comment V-C1:

1. SOLAR ENERGY

EKPC's 2009 IRP also ignores solar photovoltaic ("PV") and solar thermal. See Public Interest Groups' First Data Request, Response 37. EKPC did this without any information or data regarding future costs. See Id., Response 38. This is particularly shocking when one considers that most experts agree that solar PV will reach grid parity well before 2023. Grid parity is when solar PV costs the same as the current energy mix. The way EKPC's rates have been increasing, it will probably be much sooner than that.

As mentioned above, AEP includes significant solar in its IRP. See Kentucky Power IRP, AEP App. Vol. A at 1-2.

There are utility-scale solar energy projects in neighboring states including:

- *SunEdison is building a 16-megawatt solar farm in Davidson County, North Carolina. Because solar is a technology that can successfully be incrementally installed, the first phase of the project is beginning with a 4-megawatt capacity. Ex. V-9, SunEdison Activates First Phase of 16-MW North Carolina Solar Farm.*

- *Juwi Solar is building a 12-megawatt solar installation in Upper Sandusky, Ohio. Ex. V-b, Juwi Solar To Build 27 MW of PV Installations.*

Though Kentucky is behind in solar production compared to neighboring states, it has more to do with Kentucky's lack of renewable and efficiency portfolio standards than lack in actual solar potential. Germany, a nation leading the way in solar PV energy production, has weaker solar resources than Kentucky. Ex. V-11, Andy McDonald, The Facts Refute the Myth That Kentucky's Renewable Energy Potential is Poor.

Division's Response to Comment V-C1:
Please see the Division's Response to Comment V-C.

Comment V-C2:

2. WIND ENERGY

Wind power is a mainstream source of electric generation in the U.S. and yet EKPC's 2009 IRP does not include any plans for wind energy. Last year, wind power was the number one source in the United States and the World in terms of name plate capacity installed. Currently, there are over 35 gigawatts of installed wind power capacity in the United States. See http://www.awea.org/projects/. Texas is the state with the most installed wind power capacity, but Indiana is the state that has experienced the greatest relative growth of wind power capacity and both Indiana and Illinois have over a gigawatt of installed wind capacity. As noted above, AEP's Eastern System plans on installing 3 gigawatts. See Kentucky Power IRP, AEP App. Vol. A at 1-2. Kentucky Utilities /Louisville Gas & Electric recently applied to the Commission for the inclusion of wind power on their system. See PSC Case 2009-353 (http://psc.ky.gov/pscscf/2009%2ocases/2009 00353/).

Though it has been argued in the past that Kentucky does not have adequate wind resources to make wind energy production feasible, these assumptions were based on wind resource measurements at 50 meters. Nordex USA Inc. now makes a wind turbine designed for low to moderate wind speed with a height of 100 meters. See Ex. V-12, Nordex Receives First US N100 Order. Indiana has recently added over 500 megawatts of wind farms in areas that were formerly classified as poor wind sites by using new taller wind turbines. Ex. V-11, 1.

EKPC is oft heard to complain about its lack of ability to transmit wind power on its system. Yet EKPC is perfectly capable of building high voltage transmission lines to accommodate new fossil fuel fired capacity. Furthermore, EKPC has chosen not to join a regional transmission organization.

Moreover, in addition to the self-build option, there are a variety of efforts underway to provide market based transmission services for the delivery of wind power. See, e.g.,http://www.itctransco.com/projects/thegreenpowerexpress/thegreenpowerexpress-map.html. EKPC's 2009 IRP makes no mention of even considering these options, though they are technically feasible and being utilized by utilities in this region of the country. WA has recently signed a power- purchase agreement for 165 MW of wind energy from Gray County, Kansas. Ex. V-13, CPV Renewable Energy & WA Announce 165-MW Wind PPA. Appalachian Power of American Electric Power signed a PPA with Orion Energy for 75 MW of wind power from Camp Grove, Ill. Ex. V-14, AEP Buying 75MW of Wind from Orion.

It has also been argued that the intermittent nature of the wind limits the percentage of electricity load it can reliably provide. Other utilities have successfully integrated as much as 20% of their electricity from wind production. Ex. V-15, Clearing the Air: Wind Power and Reliability, 1.

Division's Response to Comment V-C2:
Please see the Division's Response to Comment V-C.

Comment V-C3:

3. SMALL-SCALE HYDRO POWER GENERATION

Small-scale hydro power generation is another technology that could meet EKPC's needs, to the extent they exist. This is ironic because of the proximity of the proposed plant and the Kentucky River. Between the sites owned by the Kentucky River Authority and the Army Corps of Engineers, 191.5 MW could be generated by small-scale hydro projects. See Ex. V-5, at 30.

Division's Response to Comment V-C3:
Please see the Division's Response to Comment V-C.

Comment V-C4:

4. ENERGY STORAGE

The argument that renewable sources of energy pose a dispatchability issue is not factually accurate. Current technology allows for energy storage. just a few examples of such advances are:

- *Suniva & GS Battery are planning and developing commercial demonstration sites. The first system they are designing will be the first grid-connected energy-storage solar installation in Georgia. Ex. '1-16, Sunvia & GS Battery To Develop Energy- storing Solar Systems, RenewableEnergyWorld.com (Jan. 29, 2010).*

- *Xcel Energy purchased the first direct wind energy storage batteries in the U.S. to be incorporated into a wind farm in Minnesota. Ex. V-17, Xcel Energy Launches Battery Project, RenewableEnergyWorld.com (Feb. 29, 2008). The one- megawatt battery is connected to the grid and has been running smoothly since it was first tested. Ex. V-iS, Minnesota Tests Nation's First Wind-To-Battery Storage, The Minnesota Daily (Mar. 31, 2009).*

- *VRB Power Systems of Canada has installed a two megawatt battery in the Some Hill, Buncana, Ireland wind farm, which "can make electricity from wind 95 percent constant." Ex. V19, Technological Advancements Allow Batteries To Store More Wind Energy, RenewableEnergyWorld.com (Mar. 4, 2008).*

- *Duke Energy announced in 2009 that it would design, build, and install large-scale batteries to store wind energy at its Notrees Windpower Project in Texas. Ex. V-20, Duke Receives US $22M Grant for Wind Power Storage, RenewableEnergyWorld.com (Nov. 25, 2009).*

- *Apollo Solar, is developing a less expensive, more efficient Smart Grid inverter as part of a Department of Energy funded Solar Energy Grid Integration System (SEGIS) project. The project will use a lithium ion battery system. Ex. V-21, Battery System To Provide Solar PV "Time-Shifting", RenewableEnergyWorld.com (Sept. 11, 2009).*

In addition, pump storage and compressed air are two mature, mainstream technologies that can be used for energy storage.

Division's Response to Comment V-C3:
Please see the Division's Response to Comment V-C.

Comment V-D:

D. COMBINED CYCLE NATURAL GAS

One of EKPC's most fundamental problems is using base load generating units to meet its peak demand. Base load units are much more capital intense than peaking or intermediary units. However, this is often justified by the fact that the base load units are used much more often, i.e. the capital investment is not sitting idle. However, EKPC does not distinguish between base load, intermediary load

or peak load supply-side resources in its planning model. See Environmental Groups' Second Data Request, Response 87.
The capital cost of Smith 1 versus the capital cost of a combined cycle natural gas plant are very unfavorable. EKPC is currently seeking over $920 million to pay for the Smith plant. This is over $3000 per kilowatt of capacity. As to the combined cycle plant, as explained below, Progress Energy Carolinas is building a combined cycle plant for approximately $947/kW. The California Energy Commission's most recent estimate was $1329/kW in 2009 See California Energy Commission, Comparative Costs of California Central Station Electricity Generation, Draft Staff Report at 6, 9, available at http://www.energy,ca.Qov/2009publications/CEC-200-2009-017/CEC-200- 2009-017-SD.PDF.

EKPC's problem of planning, which results in excessive and the wrong type of supply-side resources in the future, is exacerbated by the fact that EKPC does not do a reasonable analysis of its ability to sell its excess electricity off of its system. Supply-side fossil fuel resources are "lumpy," meaning you have to purchase a unit that is of a certain minimum size for technological reasons, even if you do not need that much added capacity until later. Thus, sometimes a utility needs to sell energy off-system.

Most of the states in the United States, including Ohio, have renewable portfolio standards, which are sometimes called renewable electricity standards. In addition, a national renewable portfolio standard is very likely coming. Furthermore, other states already have greenhouse gas emission limits for their electricity. This means that in the future EKPC's market to sell its excess electricity generated from its fossil fuel units will shrink.

Other utilities are moving in the opposite direction of EKPC in terms of resource planning. For example, Progress Energy Carolinas is planning on shutting down three coal-fired units and building a new combined cycle natural gas power plant that is capable of meeting base load needs. See Ex. V-22, Progress Energy to Shut Down Three Coal-Fired Power Plant Units.

Kentucky Power and its parent corporation, AEP, are also moving in the opposite direction of EKPC in terms of supply-side resources. In Kentucky Power's recently filed IRP, there are no plans for additional coal fired generation or plans for additional base load generation, but there are plans for retirement of old coal fired units, plans for natural gas-fired units to meet intermediary load, and sizeable amounts of DSM and renewables. See Kentucky Power Company Integrated Resource Plan, Case No. 2009-339, AEP App. Vol. A, Table 1 at p. 1-2.

In April of this year, in a proceeding in front of the Louisiana Public Service Commission, a utility dropped its plans to build a coal-fired unit in favor of a natural gas-fired combined cycle combustion turbine facility. See Ex. V-23, *Report and Recommendation Concerning the Little Gypsy Unit 3 Repowering Project Before the Louisiana Public Service Commission U-30192. This is further evidence of the unreasonableness of EKPC's future CFB. Part of EKPC's reluctance to plan for base load or intermediary load generating units that burn fuels other than coal may be its lack of understanding or success in the natural gas market. EKPC buys natural gas on the spot market. Staff's Second Data Request, Response 30. Poor planning ends up costing EKPC dearly. For example, EKPC paid $15.70 per MMBtu in May 2009 while the average price paid by power generators for the same month was $4.46. See Environmental Groups' Second Data Request, Request 98. For these reasons, the Proposed Plant is not needed. The DAQ should deny the permit.*

Division's Response to Comment V-D:
Please refer to the Division's Response to Comment V-C.

Comment VI:

VI. COORDINATING NEPA

DAQ should wait until the U.S. Army Corps of Engineers (Corp) completes a valid supplemental environmental impact statement ("EIS") for East Kentucky Power Cooperative's ("EKPC") proposed coal-fired circulating fluidized bed unit at its existing j.K. Smith Electric Generating Station before completing its review of the prevention of significant deterioration ("PSD") and Title V operating permit application and issuing a final decision on the permit for this facility. DAQ's permitting process would benefit from the very information produced by the EIS, which is currently underway. Moreover, coordination with the ElS process is required by 401 KAR 51:017 § 17 ("If a proposed source or modification is subject to action by a federal agency which might necessitate preparation of an environmental impact statement ...review by the cabinet conducted in accordance with this administrative regulation shall be coordinated with the broad environmental reviews under that Act and under 42 U.S.C. 7609 to the maximum extent feasible and reasonable.").

Premature permitting by DAQ would cause needless duplication, squander state agency resources, and create public confusion. EKPC's PSD/Title V application requires agency staff to gather a significant amount of information and data that the Corps is already generating for preparation of the SEIS. Coordinating the PSD/Title V permit process so it does not reach the final permit stage until after the SEIS is completed is a sounder path for the citizens of Kentucky. Synchronized review would serve agency staff and the people of Kentucky well by minimizing duplication and the needless expenditure of state resources, while also simplifying public involvement.

Division's Response to Comment VI:
The Division does not concur. 401 KAR 51:017, Section 17 provides that "[i]f a proposed source or modification is subject to action by a federal agency that may necessitate preparation of an environmental impact statement under 42 U.S.C. 4321 to 4370d (the National Environmental Policy Act), review by the cabinet conducted in accordance with this administrative regulation shall be coordinated with the broad environmental reviews under that Act and under 42 U.S.C. 7609 to the maximum extent feasible and reasonable"(emphasis added). There is no requirement that the Division delay the permitting process.

Comment VI-D-A:

A. THE SEIS WILL PROVIDE A CONSIDERABLE WEALTH OF INFORMATION.

The Corps should produce a wealth of information about the proposed Smith Station coal-fired unit which overlaps with the information the Cabinet is required to consider in the PSD/Title V permitting process. This is because NEPA explicitly requires the SEIS to fully examine the significant environmental impacts of the expansion of the Smith Station, along with transmission line and switching stations that will accompany this expansion. These impacts include:

- *Air quality impacts from emissions of particulate matter, sulfur dioxide and nitrogen oxides and other pollutants;*
- *Impacts to climate change from emissions of millions of tons of carbon dioxide and other greenhouse gases annually;*
- *Impacts to aquatic fauna due to mercury deposition; and*
- *Impacts to a number of federally and state-protected species.*
- *Impacts to other Air Quality Related Values in Class I areas such as acid deposition to soils and water and their impacts to vegetation, visibility.*
- *Impacts to soils, vegetation and visibility in Class II areas.*
- *Non-air quality health and environmental impacts and energy requirements, which must be consider in making a case by case MACT determination.*
- *Growth associated with the construction and operation of the proposed facility.*

- *Collateral environmental, energy and economic impacts from various processes and techniques to maximize the reduction of emissions from the facility which must be considered in making BACT determinations.*

- *Emission of hazardous substances in such quantities or duration as to be harmful to the health and welfare of humans, animals and plants which must be considered pursuant to 401 KAR 63:020.*

Beyond analyzing environmental impacts from the proposed project, NEPA requires that the SEIS evaluate alternatives to the proposed project. This rigorous evaluation of alternatives lies at "the heart of the environmental impact statement," 40 C.F.R. § 1502.14. Importantly, the alternatives' analysis focuses not on the narrowly defined agency action — here, the Corps issuance of the 404 permit — but instead on "the underlying purpose and need to which the agency is responding in proposing the alternatives including their proposed action," 40 C.F.R. § 1502.13. The SEIS is thus required to discuss "energy alternatives," including demand-side management, purchased power, and renewable energy, as well as other fossil-fuel generation alternatives. Finally, the SEIS is required to provide a discussion on the environmental impacts of those alternatives and how to minimize and mitigate those impacts.

If the Cabinet were to issue a final PSD/Title V permit before the SEIS process is complete, the SEIS could moot DAQ's work with regard to the PSD/Title V permit. Based on the SEIS, the Corps may select a different alternative that has fewer impacts to the environment, which could include an alternative energy method or mitigation measures to the proposed power plant. If the Corps selects a different alternative it would render moot the Cabinet's prior issuance of a PSD/Title V permit. It would be especially inappropriate for DAQ to waste such resources given that the state of Kentucky is under increasing pressure to reduce state expenditures. In any event, DAQ is required to consider alternatives to the proposed facility. See 40 C.F.R. 51.166(q)(2)(v) incorporated by reference into 401 KAR 51:017 § 15. Therefore, DAQ cannot willfully ignore the alternatives which must be put forth in the SEIS by issuing a final permit prior to the issuance of the SEIS.

Moreover, this SEIS will provide information regarding the interplay of federal, state, and local laws. That is because an SEIS must include a discussion of 'any adverse environmental effects... <u>any</u> irreversible or irretrievable commitments of resources . . . [and any] possible conflicts between the proposed action and the objectives of Federal, regional, [or] State [] policies and controls for the area concerned." 40 C.F.R. § 1502.16 (emphasis added). Impact statements must also "discuss any inconsistency of a proposed action with any approved State or local plan and laws." 40 C.F.R. § 1506.2(d).

The SEIS process will provide an excellent opportunity for sharing information with the public and other agencies, further ensuring that the information DAQ uses is accurate and complete.

Division's Response to Comment VI-D-A:
The Division does not concur. Please refer to the Division's response to Comment VI-D.

Comment VII-A:

VII. NSPS

A. EMERGENCY GENERATOR AND FIREWATER PUMP
As explained elsewhere, Smith will have to have an emergency generator(s) and/or firewater pump(s). These will be subject to a New Source Performance Standard that must be in the permit.

Division's Response to Comment VII-A:
The Division does not concur. See the Division's Response to Comment I-A.

Comment VII-B:

B. CFBs ARE MISSING PERCENT REMOVAL AND EXEMPT STARTUP, SHTUDOWN AND MALFUNCTION

The Emission limits for CFB 1 and 2 in Section B.2.b must have the following condition: 5 percent of the potential combustion concentration (95 percent reduction) on a 30-day rolling average basis. This is required by 40 C.F.R. 60.43Da(i)(1)(ii)(2009). Furthermore, the permit must have testing, monitoring and reporting to assure compliance with this condition.

In addition, the emission limit of 1.4 lb S02/MWh gross is appropriate but there is no basis to exclude emissions during startups and shutdown. Therefore, the words "startup" and "shutdown" must be deleted from Condition B.2.b.i for both CFB 1 and 2.

Division's Response to Comment VII-B:
The Division does not concur with respect to the 95 percent reduction requirement. 40 CFR 60.43Da provides the option of meeting 1.4 lb/MWh gross energy output or a 95 percent requirement.

The Division concurs that the words "startup" and "shutdown" should be deleted from Condition B.2.b.i for both CFB 1 and 2.

Comment VIII-1:

VIII. MONITORING, REPORTING AND ENFORCEABILITY

1. THE PERMIT MUST REQUIRE THE REPORTING OF ALL MONITORING

The Permit must require the reporting of all monitoring results not just violations and some select results. 40 CFR § 70.6(a)(3)(iii)(A) and 42 U.S.C. § 7661(c)(a) require that Title V permits issued by state agencies include a requirement for submittal of reports of any required monitoring at least every 6 months. Smith's permit does not contain any such requirement. It requires summary reports but does not define what a summary report is. The permit must require the reporting of all monitoring, testing and recordkeeping.

Division's Response to Comment VIII-1:
The Division does not concur that submission of raw monitoring data is required. Please refer to 40 CFR 70.6(a)(3)(iii)(A). With respect to summary report contents, see for example, Section B.6

Comment VIII-2:

2. COOLING TOWERS DO NOT HAVE ADEQUATE MONITORING

The Permit needs to require submission of records of purchase and MSDS for water treatment chemicals used in the cooling towers with the semi-annual reports to ensure compliance with operating limit B.1.d.

Division's Response to Comment VIII-2:
The Division does not concur. The permit contains adequate testing and monitoring provisions that are sufficient to ensure limitations are met.

Comment VIII-3:

3. ThE PERMIT NEEDS TESTING AND MONITORING OF OTHER POLLUTANTS

The permit must require testing and monitoring for Fluorides, H2S, sulfuric acid mist and total Reduced Sulfur compounds to ensure compliance with major source thresholds and rates stated in permit application. See 401 KAR 51:001 §1(218)(a). The same is true of with beryllium, benzene, arsenic, radionuclides, radon-222, polonium-210. See NSR manual at A.21. See a/so 401 KAR 51:001 §1(218)(b).

Division's Response to Comment VIII-3:
The Division does not concur. Section B.3 requires testing of sulfuric acid mist, benzene, arsenic, and hydrogen fluoride. Section B.3.c requires that a correlation be developed between sulfur content, limestone and fresh lime injection rates, in order to use SO2 emissions as measured by CEMS to ensure compliance with sulfuric acid mist emission limits. None of the remaining listed pollutants are estimated to approach major source thresholds.

Comment VIII-4:

4. THE PERMIT DOES NOT REQUIRE ADEQUATE TESTING OF TOTAL PM

The total PM10/PM2.5 emission limit for the CFBs is based on a 24-hour average timing although the limit in B.2.a.ii does not say if it is a rolling average or a block average. The permit needs to clarify that. Furthermore, compliance is supposed to be based on stack testing but B.3 does not specify which pollutants need to be tested and which test method should be tested. Section B.3.a for CFB1 and 2 needs to specific the performance tests that must be performed i.e. list each pollutant that needs to be tested. This must include a performance test for total PM using an appropriate test method that captures total PM, that is both filterable and condensible PM. Also, the last sentence must be clarified to state that the source shall perform a performance test within 12 months of the last performance test and must list the specific pollutants, including total PM10/PM2.5. Furthermore, additional monitoring, testing and reporting is needed because the test method will likely be based on a 3 hour averaging time but the emission limit is based on a 24 hour averaging time. In addition, the 36 lb/hr total PM10/PM2.5 applies all the time including during startups, shutdowns and malfunctions. Thus, the permit must including monitoring, testing and reporting to ensure that the CFBs are complying with this emission limit all the time, including during startup, shutdown and malfunction including malfunction of the pollution control equipment such a failure of a bag in the fabric filter or the polishing dry scrubber.

Division's Response to Comment VIII-4:
The Division concurs in part. The Compliance Demonstration language has been revised for total $PM_{10}/PM_{2.5}$. The averaging period for the BACT limit is revised to be consistent with the averaging method listed in 40 CFR 60.48Da(p).

The permit requires performance testing using applicable reference methods and procedures the methods in 40 CFR 60 Appendix A and procedures as specified in 40 CFR 60.50 Da(a). Additionally, the permit establishes a schedule for performance testing to be conducted within 12-months of the previous performance test.

As stated previously, the 36 lb/hr limit for total $PM_{10}/PM_{2.5}$ applies at all times and is reflected in the permit.

Pursuant to the BACT analysis, during the Start Up event, the permit requires only pipeline quality natural gas to be used.

Comment VIII-5:

5. OTHER PROBLEMS WITH MONITORING, TESTING AND REPORTING

The PM limits in Condition B.2.a.i for the CFBs needs to include an averaging time.

The draft permit assumes that compliance with the CO limit shall constitute compliance with the VOC limit. This is no monitoring and testing and no monitoring or testing is not adequate monitoring or testing. At a minimum, VOCs should be tested at least once every twelve months at the same time that CO is being stack tested or monitoring with CEMS to establish a statistically valid correlation. However, this could only be valid if the averaging time for CO is reduced to a 3-hour rolling average. Otherwise, there needs to be independent testing, monitoring and reporting to determine continuous compliance with the VOC emission limits.

The draft permit assumes that compliance with the SO2 limit shall constitute compliance with the sulfuric acid mist (SAM) limit. This is no monitoring and testing and no monitoring or testing is not adequate monitoring or testing. At a minimum, SAM should be stack tested at least once every twelve months at the same time that SO2 is being stack or monitored with CEMs to establish a statistically valid correlation. However, this could only be valid if the averaging time for SO2 is reduced to a 3-hour block average. Otherwise, there needs to be independent testing, monitoring and reporting to determine continuous compliance with the SAM emission limits.

As to the ash handling system, the SOB needs to establish the relationship between the gr/dscf and lbs/hour emission limits under all conditions or else compliance with the gr/dscf limit cannot be considered compliance with the lbs/hour limit. The same comment applies to the limestone silos and the lime silo storage and handling emission units. Furthermore, the draft permit only requires one stack over the lifetime of the facility. This is not adequate. Rather stack tests no less frequent than one a year must be required for each emission unit. Furthermore, a statistically significant correlation under all conditions between the gr/dscf and lb/hr emission rate and opacity and pressure drop across the FF must be established before opacity and pressure drop can be used to assure and ensure compliance.

Division's Response to Comment VIII-5:

With respect to averaging times, see the Division's Response to Comment VIII-4.

With respect to establishing a statistically valid correlation between carbon monoxide emissions and VOC emissions, the Division concurs and has modified the permit accordingly. The Division does not concur that it is appropriate to reduce the carbon monoxide 30-day rolling average to match the VOC 3-hour rolling average. Basing compliance on a 3-hour rolling average of CO CEMS data would accomplish the same purpose.

Comment IX:

IX. THE PERMIT MUST CONTAIN A CASE BY CASE MACT DETERMINATION

CFB1 is limited to 9 tons for a single HAP and 22.5 tons for all HAPs per 12-month period. Draft Permit at 24, Condition B.2.h. CFB2 is also limited to 9 tons for a single HAP and 22.5 tons for all HAP5 per 12-month period. Draft Permit at 34, Condition B.2.h. 9 plus 9 is 18 which is more than 10. 22.5 plus 22.5 is 45 which is more than 25. The SOB says that HAPs emissions from CFB1 are 13.4 tpy and from CFB2 are 13.7 tpy. SOB at 9.[119] *Again 13.4 plus 13.7 is more than 25 tpy. The Clean Air Act defines major source for MACT purposes as any station source or group of station sources located within a contiguous area and under common control that emits or has the potential to emit considering controls, in the aggregate, 10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants. 42 U.S.C. § 7412(a)(1). Two boilers at the same site owned and operated by the same company being permitted at the same time are a major source. Thus, the draft Permit is defective because it does not have a case-by-case MACT determination for CFB1 and CFB2. This defect does not appear to be a simple drafting error as the SOB also states: "To provide additional assurance that HAPs emissions remain below Section 112(g) applicability thresholds, emissions limits for each CFB shall be set at 9 tons for a single HAP and 22.5 tons for all HAPs combined for any 12- consecutive months." SOB at 9.*

Thus, DAQ must prepare a draft case-by-case MACT determination and hold a new public comment period before making a final decision on the permit. Should DAQ chose to address this issue in another way, DAQ would still be required to have a new public comment period. The public cannot be expected to guess at how DAQ will resolve a problem in the draft permit and then comment on the speculated solution.

*In any event, J.K. Smith is a major source of HAPs. Combustion Turbines 1-4 are limited to 2500 hours of operation per year each and 2.48 lbs/hr of formaldehyde for all four units. Draft Permit at 2, Condition B.1.a; at 5, Condition B.2.n. This equals 12.4 tons per year of a single HAP, making j.K. Smith a major source. (2500 hrs per yr * 4 CT5 * 2.48 lb per hr / 2000 pounds per ton = 12.4). Combustion turbines 5-7, combined, are limited to 10 tons per year of formaldehyde. Draft Permit at 11, Condition B.2.i. There are no other permit limits on HAPs for combustion turbines 5-7, including acetaldehyde and other compounds, which they can emit in non-trivial amounts. Similarly there is no acetaldehyde limit for combustion turbines 1-4.*

DAQ admits that 40 C.F.R. Part 63 Subpart YYYY is an applicable regulation to the Combustion Turbines 9&10 which DAQ considers as the same source as CFB1 and CFB2. Draft Permit at 16, SOB at 2. The SOB does not provide, nor is there, a rationale for distinguishing between applying the applicable MACT *standard, be it YYYY or the case by case MACT standard, to Combustion Turbines 9&10 and CFB1 and 2. Therefore, DAQ must prepare a case by case MACT analysis and subject it to public notice and comment.*

East Kentucky Power Cooperative's modification to the J.K. Smith Generating Station— by adding Unit 4 means that the case-by-case MACT requirements are also applicable to CFB1 and 2 via 42 U.S.C. § 7412(g)(2)(A), which provides: no person may modify a major source of hazardous air pollutants in such State, unless the Administrator (or the State) determines that the maximum achievable control technology emission limitation under this section for existing sources will be met. Such determination shall be made on a case-by-case basis where no applicable emissions limitations have been established by the Administrator.

Prior to constructing of Combustion Turbines 9&10, which are start of the same project as CFB1 & 2, the Smith power plant was a major source for hazardous air pollutants because, as explained above, it had the potential to emit greater than 10 tons of any single hazardous pollutant and more than 25 tons of all hazardous pollutants, combined, annually.

Therefore, adding CFB). and 2 as well as Combustion Turbines 9&10 was a modification for purposes of 42 U.S.C. § 7412(g)(2)(A) because it was a "physical change in... a major source which increase[d] the actual emission of any hazardous air pollutant emitted by such source by more than a de minimus amount 42 U.S.C. § 7412(a)(5). Specifically, adding well over 9 tons per year of hazardous air pollutants, after pollution controls.

There is no regulation defining "de minimus" in 42 U.S.C. § 7412(a)(5), but no regulation is necessary. To the extent that EPA has weighed in on what qualifies as a "de minimus" amount of Hazardous Air Pollutants, it has used 1000 pounds per year (0.5 tons/year), or less. See e.g., 60 Fed. Reg. 34,488 (july 3, 1995) (approving an operating permit program that includes exemptions from permit requirements for sources that emit, at most, 1000 pounds of HAP5). For other Clean Air Act programs, EPA has defined "de minimus" as 2-4% of a regulatory threshold such an ambient air quality impact standard. See e.g., 45 Fed. Reg. 52,676, 52,707-08 (August 7, 1980) (establishing "de minimus" thresholds for increases from major modifications based on estimates of emissions that will result in ambient air impacts of 2- 4% of the air quality standards); see also 61 Fed. Req. 38,292 (July 23, 1996) ("The EPA believes that where a proposed source contributes less than four percent to the [applicable air standard]," those emissions are de minimus). We believe that these thresholds of 1000 pounds or 2-4% of the regulatory standard are well beyond the reasonable meaning of "de minimus," especially for pollutants that do not have a "safe" level. But even applying them in this case as an overly generous definition of "de minimus" to East Kentucky Power Cooperative, permitting of CFB1 and 2 causes HAP emission increases are well in excess of 1000 pounds or 2-4% of regulatory *thresholds. Therefore, the case-by-case MACT requirements are an applicable requirement to CFB1 and 2.*

There also needs to be some quality control method required for the HCL CEMs. If there is an EPA approved performance specification, the Permit should state that EKPC will comply with this and submit certification of such to DAQ. If not, RATA or some other method must be specified in the Permit.

As to the missing data methodology, the Draft Permit provides that resulting data less than the mdl will be substituted with the value equaling 75% of the mdl. The Statement of Basis does not provide the factual or legal basis for using the 75% figure. It appears to a member of the public reviewing these documents as if DAQ just made up the 75% figure out of thin air. The way to ensure that emissions do not exceed the major source threshold is to require that data below the minimum detection limit be reported as at the detection limit. We strongly suspect that if such a requirement is placed in to the Permit, it will turn out that EKPC will be able to obtain an HCL CEMS with a much lower minimum detection limit than the minimum detection limit. In fact, they do exist.

In Section 5 of the Permit, Specific Record Keeping Requirements, the Permit must require the permittee to record all information needed to calculate actual HCL mass emissions from the HCL CEMS data. This would include any information to convert the HCL CEMS data, if it is in parts per million, into a mass emission rate, in pounds per hour, as well as HCL CEMS down time and substituted data.

In Section 6, Reporting, the Permit must require the permittee to report the hourly HCL emissions in mass, that is pounds per hour, including an identification of any hours in which substitute data is used, the monthly average HCL mass emissions for each month and the 12 month rolling average HCL mass emissions. For the remaining HAPs, EKPC is required to do one stack test over the lifetime of the facility. Draft permit at 35. EPA has repeatedly rejected the use of one time stack tests to assure compliance. One stack isn't good because emissions change because of fuel and because of performance. In addition, some pollutants will have higher emissions during startups, shutdowns or other less than full load testing. Therefore, the permit should require CEMS which are commercially available. See Ex. IX-1.

Division's Response to Comment IX:

The Division does not concur. In response to the Division's third Notice of Deficiency, Item No. 5, which requested a facility-wide accounting of HAPS, EKPC replied:

The information requested is not relevant to the pending application for construction and operation of two new CFBs at the existing Smith facility. The imposition of limits on HAP emissions relates only to applicability of the requirement to undergo a case-by-case MACT determination for purposes of the new units pursuant to Section 112(g) of the

Clean Air Act and its implementing regulations at 40 CFR § 63.41 — 63.43, incorporated by reference at 401 KAR 63:002. As explained in further detail below, facility-wide HAP emissions are not relevant for purposes of assessing applicability of Section 112(g) to this project.

Section 1 12(g)(2)(B) of the Clean Air Act provides that after the state's Title V permitting program is approved by EPA "no person may construct or reconstruct any major source of hazardous air pollutants" unless the agency determines that the source will meet MACT. 42 U.S.C. § 7412(g)(2)(B); 40 CFR 63 .42(c). If no MACT standard for the particular source category has been promulgated, MACT is established on a case by case basis. Id. Pursuant to 40 CFR 63.41, for sources at existing sites like Smith as contrasted with greenfields projects, the term "construct a major source" means:

> *To fabricate, erect or <u>install at any developed site a new process or production unit which in and of itself emits or has the potential to emit</u> 10 tons per year of any HAP or 25 tons per year of any combination of HAP unless the process or production unit satisfies the criteria in paragraphs (2)(i) through (vi) of this definition.*

(Emphasis added.) EKPC is taking an enforceable limit on HAP emissions from the new CFBs as explained in the permit application (Section 3.11) so that the potential to emit HAP from the "new process[es] or production unit[s]" will not exceed 10 tons of any single HAP and 25 tons of all HAP. (As noted above and in the application, the only HAP emitted in more than trace quantities is HC1.) Therefore, this project is not subject to a case-by-case MACT evaluation. Facility-wide HAP emissions are not relevant to this demonstration.

With respect to HCl CEMS, the Division does not concur. The HCl CEMS is an indicator of compliance and not the compliance demonstration method. Method 26/26A, referenced in 40 CFR 60 Appendix A, is the reference test method used to demonstrate compliance with the HCl emission limitation. Using 75% of the minimum detection level is appropriate for substitution of missing data values, rather than using a value of zero or the minimum detection level.

With respect to the suggested modifications to recordkeeping requirements of the permit, the Division does not concur. B.5.a of the permit already requires that records be maintained of all information needed to demonstrate compliance, including performance tests, monitoring data, fuel analyses, and calculations.

<u>Comment X-1:</u>

X. MISCELLANEOUS
We have the following miscellaneous comments.

• Why is there no emission unit #8?

Division's Response to Comment X-1:
There is no requirement that there be a unit #8.

Comment X-2:

> • *Table 6-1 in the SOB incorrectly states the lead NAAQS. The lead NAAQS is 0.15 ug/m3.*

Division's Response to Comment X-2:
The Division concurs and revises the Statement of Basis accordingly.

Comment X-3:

> • *The estimated construction commence date should be removed as it can be misleading. As EKPC does not currently have financing for the CFBs and does not even have PSC approval to obtain financing, EKPC is not going to commence construction in 2010.*

Division's Response to Comment X-3:
The Division does not concur. Whether or not an applicant has received financing is not relevant. However, some of the construction dates were listed as "estimated 2009". The Division has adjusted all construction dates to "estimated 2010" or later.

Comment X-4:

> • *The Clean Air Act 112(r) program is not listed as an applicable regulation and the SOB does not explain why it is not an applicable requirement in light of the ammonia for the SNCR. The permit should be changed to include the Clean Air Act 112(r) requirements or the SOB should explain why it does not apply.*

Division's Response to Comment X-4:
The Division does not concur. Section 112(r) is implemented in Section G.9, Risk Management Provisions, of the permit.

Comment X-5:

> • *The draft permit states that 401 KAR 51:160 is an applicable regulation for CFB1 and 2. Draft permit at 21, 31. However, the draft permit does not contain the requirements set forth in 401 KAR 51:160 § 3-7 but it should. To the extent DAQ believes that the permit does not need to include these provisions, the SOB must explain the factual and legal basis for this conclusion.*

Division's Response to Comment X-5:
Page 14 of the Statement of Basis includes an explanation of 401 KAR 51:160, NO_X Budget Trading Program. Sections 3-7 are incorporated either in Section K of the permit or the CAIR

permit application. Section K.2 requires the source to operate in compliance with the requirements contained in the application.

Comment X-6:

• *The estimated 2009 construction date for the coal stockpile storage and handling is incorrect or EKPC has commenced construction without a permit. DAQ should conduct a site investigate to determine if EKPC has commenced construction without a permit. If not, this date should be corrected.*

Division's Response to Comment X-6:
The Division does not concur. The Division has corrected the tentative construction date, as well as other emission units that erroneously listed 2009 as the estimated date of construction.

Comment X-7:

• *401 KAR 63:010 is an applicable requirement to Emission Unit 15-01, 15-02, 15-03, 15-04, and 15-05 if 40 C.F.R. 60.254(b)(1) is not. The draft permit at page 49 does not state which emission units 40 C.F.R. 60.254(b)(1) applies to which creates confusion which makes the permit not enforceable as a practical matter. Condition B.2 on page 49 must state which emission units 40 C.F.R. 60.254(b)(1) applies to and must apply 401 KAR 63:010 to all those emission units that 40 C.F.R. 60.254(b)(1) does not apply to. If 401 KAR 63:010 applies, then there needs to be sufficient monitoring, testing and reporting to ensure compliance with it.*

Division's Response to Comment X-7:
The Division does not concur. The permit does not establish that 401 KAR 63:010 is applicable to the emission units listed above. 40 CFR 60, Subpart Y applies to each emission unit.

Comment X-8:

• *The note under the table on page 57 does not appear to below there. If it does belong there, the statement of basis should explain why it belongs there.*

Division's Response to Comment X-8:
The Division concurs and has deleted the note.

Comment X-9:

• *401 KAR 50:042 is an applicable regulation. However, the draft permit does not list it as an applicable regulation for CFB1 and 2 nor any other emission unit. It should. Moreover, the Statement of Basis must provide the factual and legal basis for DAQ implicit determination that the source complied with this regulation. DAQ must conduct its analysis to determine if there is compliance with 401 KAR*

50:042 and then hold a new public comment period to allow people to review this determination.

Division's Response to Comment X-9:
The Division does not concur. 401 KAR 50:042 is listed and discussed on page 13 of the Statement of Basis.

401 KAR 50:042 states that for any stack height greater than Good Engineering Practice that the excess height shall not be used in any air dispersion modeling demonstrations. DAQ requires applicants to submit a review of GEP in their application (Form DEP 7007Y). GEP heights are reviewed during any required modeling. The stack height modeling was performed in accordance with applicable standards and regulatory requirements.

Comment X-10:

• The SOB says that EKPC expects construction to commence in 2010. SOB at 2, This is not accurate. EKPC does not have financing for CFB1 and does not even have PSC approval for financing. Therefore, DAQ needs to require EKPC to update its application with correct information about when EKPC actually expects to commence construction.

Division's Response to Comment X-10:
Project financing goes beyond the scope of an air permit application review. 401 KAR 52:020 Section 7, Duty to Supplement or Correct Application, requires applicants to correct information upon discovery of the occurrence.

Comment X-11:

• The SOB says that EKPC will be required to submit an updated BACT analysis within 18 months of beginning construction of CFB2. SOB at 2. To begin with, this requirement is not in the draft permit. It needs to be in the permit. Furthermore, it should be clarified to say that it means that the updated BACT analysis has to be submitted before EKPC begins construction on CFB1. Finally, it should require an updated air impacts analysis as well as an updated BACT analysis. There will be a new primary SOx NAAQS, ozone NMQS, PM2.5 NAAQS and possibly a new secondary SOx/NOx NAAQS before EKPC commences construction on CFB2. EKPC must demonstrate that it will not cause or contribute to violations of these new standards.

Division's Response to Comment X-11:
The Division does not concur. 401 KAR 51:017 is listed as an applicable requirement. 401 KAR 51:017, Section 8(4) states:

(4) *For phased construction projects:*

(a) The cabinet shall review and modify, as appropriate, the BACT determination at the latest reasonable time occurring not later than

eighteen (18) months prior to commencement of construction of each independent phase of the project; and

(b) If requested by the cabinet, the owner or operator of the applicable stationary source shall demonstrate the adequacy of a previous BACT determination for the source.

Section 11, Air Quality Analysis, does not contain a similar provision.

<u>Comment X-12:</u>

> • *Table 4-1 of the SOB does not address whether the CFBs and Crs are trigger PSD for ozone. They do. Therefore, the SOB needs to be corrected.*

<u>Division's Response to Comment X-12:</u>
Table 4-1 listed the VOC PSD threshold as 40 tons per year, which is the actual trigger for ozone applicability. This has been clarified by adding the word "ozone".

<u>Comment X-13:</u>

> • *The SOB explains that DAQ is using the vacated mercury NSPS to ensure compliance with 401 KAR 63:030. SOB at 10-11. This is arbitrary. To begin with, the vacated mercury NSPS were vacated so they aren't valid. Using a vacated standard is arbitrary. Furthermore, the NSPS are a technology based standard. 401 KAR 63:020 is a risk based standard. Using a technology based standard to meet a risk based standard is arbitrary. Rather, all of the water bodies in Kentucky have fish consumption advisories because they have unsafe levels of mercury in them. One cannot add more pollution to an unsafe level of pollution and somehow get a safe level of pollution. Thus the CFBs should be required to emit zero mercury emissions to comply with 401 KAR 63:020. Because this is not possible at a coal fired CFB with current technology, DAQ-must deny the permit.*

<u>Division's Response to Comment X-13:</u>
The Division does not concur. EKPC performed a Toxic Air Pollutant Risk Assessment to demonstrate compliance with 401 KAR 63:020, which states that:

> No owner or operator shall allow any affected facility to emit potentially hazardous matter or toxic substances in such quantities or duration as to be harmful to the health and welfare of humans, animals and plants.

The Division determined air toxic emissions from the proposed project to be in compliance with the requirements of 401 KAR 63:020. Please note: In the absence of a mercury limitation in the permit, the emissions of mercury would not be restricted.

Comment X-14:

• . The permit application claims that ash will be transported off site for disposal. Ex. I-i at pdf 655. However, EKPC has represented to the US Army Corp of Engineers and the KY Division of Waste that the ash will be disposed of on site. Thus, EKPC has told regulatory agencies different stories. EKPC needs to correct the application to DAQ or to DOW and the Army Corp. If the ash is to be disposed of on site, then ash from the "beneficial reuse" and the "landfill" need to be including in the PM modeling.

Division's Response to Comment X-14:
The Division acknowledges the comment. Please see EKPC's response submitted on February 25, 2010, at Page 57 to this comment.

Comment X-15:

• Condition B.1 on page 49 of the Draft Permit must include a requirement that the approval of the applicant's fugitive coal dust emissions control plan must result in a modification to the applicant's Title V permit, and must provide the public adequate opportunity and time for notice and comment.

Division's Response to Comment X-15:
The Division does not concur. Until the fugitive coal dust emissions control plan is filed, it is not possible to know if the plan will result in a modification the Title V permit. As the U.S. EPA noted in the preamble to the October 8, 2009 ruling in its response to a similar comment:

"Response: The requirement to control fugitive coal dust emissions by operating according to a written fugitive dust emissions control plan is a Federal requirement and is Federally enforceable. The final rule does not require approval of the plans by the Administrator or delegated authority. In addition, the commenter does not identify any provision of CAA section 111 that would require the NSPS itself to establish a notice and comment process for the plans. However, this rule does require the owner/operator to submit the fugitive coal dust emissions control plan to the Administrator or delegated authority to provide an opportunity for the Administrator or delegated authority to object to the fugitive coal dust emissions control plan. The final rule requires the owner/operator to submit the fugitive coal dust emissions control plan to the Administrator or delegated authority before startup of the new, reconstructed of modified facility. If an objection is raised, the owner/operator has 30 days from receipt of the objection to respond with a revised fugitive coal dust emissions control plan. The owner/operator must operate in accordance with the revised fugitive coal dust emissions control plan.

The requirement for the owner/operator to prepare and operate according to a submitted fugitive coal dust emissions control plan that is appropriate for site *conditions must be included in the title V operating permit for the source. This and other requirements for title V permits are addressed in 40 CFR part 70."*

The permit contains the requirement to submit a fugitive coal dust emissions control plan as required by the regulation.

Comment X-16:

• The CFBs will emit several toxic chemicals that are known to be carcinogens. A screening level analysis has been performed for selected toxics. This analysis compares the maximum annual concentrations of these carcinogens against acceptable ambient concentrations. Thus, it only focuses on inhalation risk and, hence, understates potential health effects by ignoring non-inhalation risks such as ingestion of soil, dermal exposure, drinking water, food and usually the most sensitive receptor which is a breast feeding infant. Non-inhalation risks from multipathway pollutants such as arsenic and PAH are several times larger than inhalation risks. In its screening risk assessment guidelines, South Coast Air Quality Management District has recommended multiplying factors of 4.78 (for arsenic), 4.19 (for lead), 29.76 (for PAH) to account for non-inhalation risks (SCAQMD, 2009). Thus, the screening analysis in the PSD Application severely underestimates the cancer risks by not considering the non-inhalation health risks. A full health risk assessment will need to be conducted to assess potential health effects of the toxic chemicals emitted by the CFBs as part of public health and environmental justice concerns. One possibility is that AMI has developed a model named ACEHWCF (Assessment of Chemical Exposure for Hazardous Waste Facilities) that can evaluate both inhalation and non-inhalation risks using the multi- pathway exposure algorithms recommended by the U.S. EPA (Human Health Risk Assessment Protocol for Hazardous Waste Facilities, F/nat EPAS3O-R-05-006, September2005). The ACEHWCF model has been described in a technical paper (Tran, 2001) that is available from AMI's website.

Division's Response to Comment X-16:
The Division does not concur. There is no regulatory basis for evaluating non-inhalation risks for PSD purposes or for conducting a full multi-pathway human health risk assessment. In addition, the South Coast Air Quality Management District guidelines are not applicable to Kentucky.

Comment X-17:

• Although not necessary, a lot of needless litigation in enforcement actions could be avoided if DAQ includes explicit credible evidence language in the permit. In conclusion, we appreciate your careful review and consideration of these comments. We are hopeful that you would deny this permit as a first step towards DAQ working to Kentuckians have healthy air as we move into the Clean Energy Economy

Division's Response to Comment X-17:
The Division does not concur with respect to the statement relating to "credible evidence". Kentucky's SIP is consistent with 40 CFR 51.212(c) and does not preclude the use of credible evidence. *In the matter of: Tennessee Valley Authority* (Petition No. !V-2007-3) (July 13, 2009)

Footnotes:

1 Headings are simply for organizational convenience and should not be interpreted to limit the scope of any particular comment. For example, we may submit a comment on enforceability under the Ambient Impacts Analysis section.

2 We are providing some exhibits in paper format and some exhibits in electronic format To the extent DAQ cannot open any of the electronic format exhibits, please let the undersigned counsel know and we will work to provide you with an electronic format that you can open, or with a paper format We also reference documents that are already in DAQ and/or the Energy and Environment Cabinet's files. These documents are hereby incorporated herein by reference and must be considered part of the Administrative Record. To the extent these documents are marked as confidential, DAQ should work with the United States Environmental Protection Agency (EPA) to ensure that EPA has access to these documents when reviewing the proposed permit should DAQ decide to issue a proposed permit, which we expect that it will not We also reference items available on the internet These items are hereby incorporated herein by reference and must be considered part of the Administrative Record.

3 This exhibits also contains the legal authority of why DAQ has to supply the data, which are incorporate hereby by reference.

4 See US EPA, "PM2.5 NAAQS Implementation," available at htt//www.epa.gov/ttnnaaqs/pm/pm25_index.html; see also U.S. EPA Office of Air Quality Planning and Standards, "Review of the National Ambient Air Quality Standards for Particulate Matter: Policy Assessment of Scientific and Technical Information." Staff Paper (July 1996) ("PM2.5 Staff Paper"), available at http://www.epa.gov/ttn/naaqs/standards/pm/s_pm_1997_sp.html, at V-58 to V-77 (discussing health studies of fine versus coarse particles)

5 PM2.5 Staff Paper at V-77.

6 Clean Air Fine Particle Implementation Rule, 72 Fed. Reg. 20586, 20586-20587 (Apr. 25, 2007) (to be codified at 40 C.F.R. Part 51)

7 See National Ambient Air Quality Standards for Particulate Matter, Proposed Rule, 71 Fed. keg. 2620, 2627 (Jan 17, 2006).

8 *See Statement of Katherine M. Shea, MD, MPH, FAAP, On Behalf of the American Academy of Pediatrics, Before the Clean Air Scientific Advisory Committee to the U.S. Environmental Protection Agency, Regarding National Ambient Air Quality Standards for Particulate Matter, available at http://www.cleanairstandards.orglarticle/2005/04/390*

9 *See, e.g., T. Lewis, et al., Pollution-Associated Changes in Lung Function among Asthmatic Children in Detroit, Environ Health Perspect 113:1068—1075(2005)*

10 *Asthma Initiative of Michigan and Michigan Dept. of Community Health, Epidemiology of Asthma in Michigan: 2004 Surveillance Report, available at http://www.alam.org/Education/astats.asp*

11 *See, e.g., 71 Fed. Reg. at 2637.*

12 *Id.*

13 *L Deck (Abt Associates), "Particulate-Related Health Impacts of Emissions in 2001 From 41 Major US Power Plants," Nov. 2002, available at http://www.environmentalintegrity.org/pub80.cfm*

14 *See Levy et al, "The Importance of Population Susceptibility for Air Pollution Risk Assessment: A Case Study of Power Plants Near Washington, DC," Environ Health Perspect 110:1253—1260 at 1257 (2002) (Figure 2 showing combined concentration reductions from emissions controls at power plants, in terms olprimary PM2.5, secondary PM.25, and total PM2.5), available at http://www.ncbi.nlni.nih.gov/pmc/articles/PMC1241114/pdf/ehp0110-001253.pdf.*

15 *See, e.g., id, see also Ex. 111-A-I (J Levy et al, Using CALPUFF to Evaluate the impacts of power plant emissions in Illinois: model sensitivity and implications, Atmospheric Environment 36 (2002)1063—1075); J Levy and J Spengler, Modeling the Benefits of Power Plant Emissions Controls, J. Air & Waste Manage. Assoc. 52:5-18 (2002).*

16 *Deck, infra note 11, at Table C.*

17 *See National Ambient Air Quality Standards for Particulate Matter; Proposed Rule, 71 Fed. Reg. 2620, 2627 (Jan. 17, 2006)*

18 *The information provided by the Kentucky DAQ only covered SO2 ambient concentrations for a period of 22 months, from June 2004 to March 2006.*

19 *Sulfur Dioxide concentration levels were converted from ppm to* $\mu g/m^3$ *using the converter on EPA's website, found at*

http://www.epa.gov/apti/bces/module2/concentrate/concentrate.httn#mass (last viewed Feb.10, 2010).

20 *DAQ should do a site inspection on the facility at question to ensure the roads are indeed paved.*

21 *Reviewing the application leads the reader to believe that the emission rate calculations for the haul road are straightforward and did in fact include a precipitation factor. However, only through examining the complex modeling data is the reader able to determine that EKPC did not use the precipitation factor.*

22 *The precipitation factor in our calculation is very generous to EKPC as it uses 3,120 hours of measurable rainfall to account for the roughly 130 days where there was measurable precipitation, though it is extremely unlikely that it did in fact rain 24 hours a day for each one of those days. We also included the control efficiency factor of 0.5 (50%), though there are no enforceable limits anywhere in the permit to guarantee this.*

23 *ALA, "Diesel Exhaust and Air Pollution," available at http://www.savethebuckeyeorg/facts/DieselExhaustandAirPollutionALAOhio.pdf.*

24 *USEPA, Revision to the Guideline on Air quality Models: Adoption of a Preferred General Purnose (Flat and Compex Terrain Dispersion Model and Other Revisions, Appendix W to 40 CFR Part 51, November 9, 2005. DAQ claimed to have followed this. See SOB at 43.*

25 *The EPA announced in September 2009 that it "expects soon to promulgate regulations under the Clean Air Act to control GHG emissions and, as a result, trigger PSD and Title V applicability requirements for GHG emissions." See Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule; Proposed Rule, 74 Fed. Reg. 55,292 (October 27, 2009).*

26 *The EKPC application does not contain enough information for a precise estimate of greenhouse gas emissions. EKPC must provide more detailed information on processes and emission points as part of an Application Addendum that includes estimates of greenhouse gas emissions.*

27 *EPA's proposed rule would "phase in the applicability thresholds for both the PSD and title V programs for sources of GHG emissions. The first phase, which would last 6 years, would establish a temporary level for the PSD and title v applicability thresholds at 25,000 tons per year (tpy), on a "carbon dioxide equivalent" (C02e) basis, and a temporary PSD significance level for GHG emissions of between 10,000 and 25,000 tpy C02e." 74 Fed. Reg. at 55291.*

28 See *http://www.ipcc.ch/ipccreports/assessments-reports.htm;* *EPA, Ground-Level Ozone: Health and Environment, March 6. 2007,* *http://www.epa.pov/air/ozone pollution/health.html;* *EPA, Particulate Matter: Health and Environment, January 17, 2008,* *httjx//www.epa.gov/air/particlepollution/health.html* *Jonathan A. Patz, et al., Impact of Regional Climate Change on Human Health, Nature, 438, 310-317, November 17, 2005,* *http://www.nature.com/nature/journal/v438/n7066/full/nature04188.html;* *EPA, Climate Change, Health and Environmental Effects, December 20, 2007,* *http://www.epa.gov/climatechange/effects/health .html;* *See also, Centers for Disease Control, CDC Policy on Climate Change and Public Health, available at* *http://www.cdc.gov/climatechange/pubs/Climate Change Policy.pdf.*

29 U.S. Environmental Protection Agency, Final Rule, Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the Clean Air Act, December 7, 2009, Docket ID No. EPA-HQ-OAR-2009-0171; available at *http://www.epa.gov/climatechange/endangerment/downloads/FinalFindings.pdf.*

30 EPA Proposed Endangerment and Cause or Contribute Findings for Greenhouse Gases Under section 202(a) of the Clean Air Act; Proposed Rule, 74 Fed. Reg. 18886, 18904 (April 24, 2009).

31 Id.

32 U.S. Environmental Protection Agency, Final Rule, Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the Clean Air Act, December 7, 2009, Docket ID No. EPA -HQ-OAR-2009-01 71 at 10; available at *http://www.epa.gov/climatechange/endangerment/downloads/Final findings.pdf.* *More information about the IPCC is available at* *http://lwww.ipcc.ch /about/index.htm.*

34 See National Wildlife Federation, Global warming and Kentucky, available at http://www.nwf.org/GlobaI-warming/~/media/PDFs/Global%20warming/Global%20Warming% 20State%2oFact%2osheets/Kentucky.ashx

35 See http://www.ucar.edu/news/releases/2008/climate-threat.jsp.

36 Obama to Go to Copenhagen With Emissions Target; *http://www.nvtimes.com/2009/11126/us/politics/26climate.html?emc=etal.* *Even if such legislation confers "grandfathered-in" status upon existing or already-approved coal plants, then emissions from the Smith plant might constrain*

Kentucky's flexibility in that the state might have fewer carbon allowances to allocate to other carbon emitters.

37 *The EPA announced in September 2009 that it "expects soon to promulgate regulations under the clean Air Act to control GHG emissions and, as a result, trigger PSD and Title v applicability requirements for GHG emissions." See Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule; Proposed Rule, 74 Fed. Reg. 55,292 (October 27, 2009).*

38 *See. e.g., Mt. code 69-8-421(7); Del. Admin. Code 7 1000 1144 § 3.2.1.1, 3.2.2.1; Wash. Rev, code 80.80; Cal. Pub, Util. Code § 8341.*

39 *Kansas Dept. of Health and the Environment, Press Release: KDHE Electric Denies Sunflower Electric Air Quality Permit, October 18, 2007, available at http://www.kdheks.gov/news/web_archives/2007/10182007a.htm.*

40 *42 U.S.C. § 7475(a)(4); see also 40 CFR § 52.21(b)(50) (2007).*

41 *EPA's proposed rule would "phase in the applicability thresholds for both the PSD and title V programs for sources of GHG emissions. The first phase, which would last 6 years, would establish a temporary level for the PSD and title v applicability thresholds at 25,000 tons per year (tpy), on a "carbon dioxide equivalent" (CO2e) basis, and a temporary PSD significance level for GHG emissions of between 10,000 and 25,000 tpy CO2e." 74 Fed. Reg. at 55291.*

42 *42 U.S.C. § 7475(a)(3); 40 CFR § 52.21(j)(2); see also e.g., In re Northern Michigan University Ripley Heating P/ant, PSD Appeal No. 08-02, Slip Op. at 31-32 (EAB February 18,2009) (remanding permit for consideration of whether BACT for CO2 and N20 is required).*

43 *See Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule; Proposed Rule. 74 Fed. Reg. 55,292 (October 27, 2009).*

44 *The CFBs at the Smith Facility would unquestionably also emit nitrous oxide (N20). See, e.g., S. Korhonen, et al., Methane and Nitrous Oxide Emissions in the Finnish Energy Product/on at p. 2(36) (May 2001) (attached as Exhibit lv.A.25).*

45 *See CO2 BACT Analysis for Cash creek Generating Station, dated December 2008 (attached as Exhibit lv.A.3).*

46 *See Statement of Basis for Draft Amended Federal "Prevention of Significant Deterioration" Permit - Russell city Energy Center at 62-63 (December 8, 2008) (establishing a C02 limit of 1100 lb/MMBtu for the Russell City Energy Center) (attached as Exhibit IV.A.5); see also Idaho Department of Air*

Quality, Power County Advanced Energy Center — Air Quality Permit to Construct Number 2008.066, issued to Southeast Idaho Energy, LLC, Feb. 10, 2009, available at http://www.deq.idaho.gov/air/permits_forms/ptc_final/se_idaho_energy_power_county_ptc_1109_permit.pdf (Conditions 7.3-7.7 on page 39 require that C02 emissions are limited by 58% by weight or to 750,000 tons per year from the Acid Gas Removal stream C02 vent. Exceedance of the limit is a violation of the permit. The permittee is required to permanently sequester carbon dioxide emissions).

47 *Standards of Performance for New Stationary Sources and Guidelines for Control of Existing Sources: Municipal Solid Waste Landfills, Final Rule and Guidance, 61 Fed. Reg. 9905 (Mar. 12, 1996).*

48 *74 Fed. Reg. 32744 July 8, 2009).*

49 *74 Fed. Req. 32752.*

50 *Id. at 32746.*

51 *See 40 CFR 85.2304.*

52 *Cal. Code RTEC. tit. 13, § 1961.1(a); Conn. Agencies RTEC. § 22a-174-36b(b)(3); 06-096- 127 Me. code R. § 1(B)(4); 310 Mass. code RTEC. 7.40(2)(a)(6); N.J. Admin. code § 7:27- 29.13; N.Y. Comp. codes R. & RTEC tit. 6, § 218-8.2; Or. Admin. R 340-257-0050(2)(e); 25 Pa. Code 124.412; see also 36 Pa. Bull. 7424; 12-031 RI. Code R. § 37.2.3; 12-031-001 Vt. code R. § 5-1106(a)(5); Wash. Admin. Code 173-423-090(2). In three more states and the District of Columbia, these standards will come into effect in subsequent model years. Ariz. Admin. code § R18-2-1801; Md. Code RTEC. 26.11.34.03; N.M. code R. § 20.2.88.101; D.C. Law 17-0151.*

53 *42 U.S.C. § 7507.*

54 *Id. at 1173.*

55 *Motor Vehicle Manufacturers Association v. New York State Department of EnvIronmental Conservation, 17 F.3d 521, 529 (2d. Cir. 1994).*

56 *See, e.g., 40 CFR § 52.370(c)(79) (EPA approval of §177-adopted standards as part of Connecticut's SIP); 40 CFR § 52.1020(c)(58) (Maine); 40 CFR § 52.1120(c)(132) (Massachusetts); 40 CFR §52.1570(c)(84)(i)(A) (New jersey); 40 CFR § 52.2063(c)(141)(i)(C) (Pennsylvania).*

57 *See, e.g.. 42 U.S.C. § 7413; 42 U.S.C. § 7604(a)(1), (f)(3).*

58 *Because the CO2 Emission Limits also provide significant criteria pollutant benefits (74 Fed. Reg. 32,744, 32.758 (July 8, 2009)) California has already included these emissions reductions into its 2007 ozone and PM SIP submittals to EPA. http://www.arb.ca.gov/planning/sip/2OQ7sip/2007sip.htm.*

59 *73 Fed. Reg. 23,101 (April 29, 2008); 40 CFR § 52.420(c); see also Letter from Brian L. Doster, U.S. Environmental Protection Agency, US EPA Air and Radiation Law Office, to Eurika Durr, EAB, September 9, 2008: "... Office of General Counsel ... believe that it is incumbent on them, in recognition of a duty of candor, to inform the Board of a recent action by the Agency... EPA Region 3 issued a final approval of a Delaware SIP revision incorporating state regulations which include specific limitations on the rate of several pollutants, including carbon dioxide;"*

60 *40 CFR § 52.420(c) (adopting Del. Admin.Code 7 1000-1144 by reference).*

61 *Delaware Department of Natural Resources and Environmental Control, Department of Air and Waste Management, Air Quality Management Section, Regulation No. 1144 § 3.2.1 — 3.2.2; http://regulations.delaware.gov/AdminCode/title7/1000/1100/1144.shtml#TopOfPage.*

62 *Id. at §§ 4.0, 6.0, 7.0*

63 *73 Fed. Req. 11845, 11846 (March 5, 2008).*

64 *73 Fed. Req. 11845.*

65 *73 Fed. Reg. 23101 (April29, 2008).*

66 *73 Fed. Req. at 11845; 73 Fed. Req. at 23101.*

67 *40 CFR § 60.33c, 60.752.*

68 *40 CFR § 60.751.*

69 *See U.S. Environmental Protection Agency. Air Emissions from Municipal Solid Waste Landfills, explaining that "MSW landfill emissions, or [landfill gas], is composed of methane, CO2, and NMOC."*

70 *See also 56 Fed. Reg. 24468 (May 30, 1991): "Today's notice designates air emissions from MSW landfills, hereafter referred to as 'MSW landfill emissions,' as the air pollutant to be controlled."*

71 *See U.S. Environmental Protection Agency, Air Emissions from Municipal Solid Waste Landfills, at 2-15.*

72 *See 56 Fed. Reg. 24468, 24481 (May 30, 1991) ("[i]n considering which alternative to propose as BDT, EPA decided to consider both NMOC's and methane reductions"); 61 Fed. Reg. 9905, 9906 (Mar. 12, 1996) ("Briefly, specific health and welfare effects from [landfill gas] emissions are as follows ... methane emissions ... contribute to global climate change as a major greenhouse gas"); Id. at 9914 (anticipated "methane reductions ... are also an important part of the total carbon reductions identified under the Administration's 1993 climate change Action Plan").*

73 *42 U.S.C. § 7651k(e).*

74 *See 43 Fed. Req. 26,388, 26,397 (June 19, 1978); In Re: Deseret Power Electric Cooperative, PSD Appeal No. 07-03, Slip Op. at 41 (Nov. 13, 2008). (attached as Exhibit IV.A.1) (holding that the fact that CO2 is regulated by rules contained in 40 CFR Subchapter C "augers in favor" of a conclusion that co2 is "subject to regulation under the Act," based on EPA's official interpretation in its 1978 rulemaking).*

75 *We further note the N20 is subject to regulation under the Clean Air Act's mobile source anti-tampering rules which prohibit the installation of a N20 system in cars. Furthermore, although EPA uses nitrogen dioxide as the indicator, the current NAAQS is for oxides of nitrogen, of which N20 is one. See e.g. Integrated Science Assessment of oxides of nitrogen and sulfur, Chapter 2.2.3 (sources of N20 emissions) available at http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm ?deid=201485*

76 *Power Industry News, Operation of World's First Supercritical CM Steam Generator Begins in Poland, available at http://www.powermap.com /coal/Operation-of-Worlds-FirstSupercritical-CFB-Steam-Generator-Begins-in-Poland 2117.html (attached as Exhibit IV.A.6); see also Process Engineering, Lagisza power plant operates CFB steam generator (July 9, 2009) (attached as Exhibit lv.A.7); Project Specifications, Lagisza Power Plant Supercritical circulating Fluidized Bed. Poland (attached as Exhibit lv.A.8); Power Technology. Lagisza Power Plant Supercritical circulating Fluidized Bed, Poland (attached as Exhibit IV.A.9); Future solutions meet in PKE S.A. Lagisza Power Plant (attached as Exhibit lv.A.10); Alstom, Carbon Abatement Technologies for Fossil Fuel Power Generation the Transition to Zero Emission (attached as Exhibit IV.A.11).*

77 *Power Industry News, Operation of World's First Supercritical CFB Steam Generator Begins in Poland, available at http://www.powermag.com/coal/ Operation-of-Worlds-FirstSupercritical-CFB-Steam-Generator-Begins-in-Poland 2117 html (attached as Exhibit lV.A.6).*

78 *Id*

79 *Id.*

80 *Power Industry News, Operation of World's First Supercritical CFB Steam Generator Begins in Poland, available at http://www.powermap.com/coal /Operation-of-Worlds-First-Supercritical-CFB-Steam-Generator-Begins-in-Poland 2117.htmi (attached as Exhibit IV.A.6).*

81 *See Utility E-Alert #905 (Jan. 2, 2009) (attached as Exhibit IV.A.12) for a discussion of how a coal/biomass combination reduces greenhouse gases.*

82 *Southeast Farm Press, Switchgrass used to fuel Kentucky power plant Jan. 7, 2009), available at http:/lsoutheastfarmpress.com/biofuels/biofuels-switchgrass-0107/ (attached as Exhibit IV.A.13).*

83 *State Tobacco Panel hears Benefits of Switchgrass (May 6, 2009) (attached as Exhibit IV.A.14).*

84 *State Tobacco Panel hears Benefits of Switchgrass (May 6, 2009) (attached as Exhibit IV.A.14).*

85 *See Congressional Testimony of David K. Garman, available at http://www1 .eere.energy.gov/office_eere/m/congressional_test_050604. html; see also U.S. Forest Service, Research Note NRS-3, Illinois' Forest Resources, 2006 (attached as Exhibit IV.A.15); U.S. Department of Energy - Energy Efficiency and Renewable Energy Alternative Fuels and Advanced vehicles Data center: Illinois State Assessment for Biomass Resources, available at http://www.afdc.energy.gov/afdc/sabre/sabre.php (attached as Exhibit Iv.A.16).*

86 *Jennifer Donovan, Michigan Utility and MTU Join Forces To Study Biomass-powered Electricity (attached as Exhibit IV.A.17).*

87 *Id.*

88 *Id*

89 *Renewable Energy world, 312 MW of Biomass to Power Burger Production in Ohio (attached as Exhibit IV.A.18).*

90 *AMP Press Release (Nov. 25. 2009) (attached as Exhibit IV.A.19).*

91 *G. Wiltsee, Appel consultants, Inc., Lessons Learned from Existing Biomass Power Plants at p. 8 (Feb. 2000) (attached as Exhibit IV.A.20).*

92 *Burning Issues: An Update on the Wood Pellet Market (April 7, 2009) (attached as Exhibit IV.A.21).*

93 Dave Williams, Power plant uses coal, grass (July 5, 2003) (attached as Exhibit IV.A.22).

94 Joaquin Air Pollution control District, Notice of Preliminary Determination (Oct. 8, 2009) (attached as Exhibit Iv.A.26).

95 Burns and Roe Enterprises Technology Selection Study, wolverine clean Energy Venture for Rogers city, MI at p. 67 (Sept. 2007) (attached as Exhibit IV.A.23).

96 Utility E-Alert #903 (Dec. 12, 2008) (attached as Exhibit IV.A.24).

97 Id

98 Available at http://www.deo.virginia.gov/export/sites/default/info/pdf/vchec/BoardBook/Attachment B 112g Comments.pdf

99 Exhibits in this section are from the Sierra Club v. EPPC & EKPC, File No. DAQ 27974-037. The exhibits are already in DAQ's files and therefore will not be provided here but are hereby incorporated herein by reference.

100 We further incorporate EKPC Ex. 5, which was admitted under seal, hereby by reference.

101 EKPC's application and KDAQ's analysis purports to follow the NSR Manual. See SOB at 17; In re E. Ky. Power Coop. Inc. Hugh L. Spurlock Generating Station, Petition IV-2006-4, Order at 28 (Adm'r, August 30, 2007).

102 NSFS/ NESHAI' requirements or the application of controls, including other controls necessary to comply with State or local air pollution regulations, are not considered in calculating the baseline emissions." NSR Manual at B.37.

103 Sierra Club does not agree that these assumptions are correct However, even using DAQ's assumptions that are overly beneficial to EKPC, a wet scrubber is clearly cost effective.

104 The SOB compares the total control from a dry scrubber plus limestone injection to the total control of wet scrubbing plus limestone injection as 99% to 99.1%, respectively. The total control from limestone injection plus 99% control of the S02 existing the boiler with a wet scrubber would be greater than the 99.1% attributed to the wet scrubber in DAQ's SOB.

105 See EPA Docket EPA-HQ-OAR-2005-0031-0123.

106 *Commercial Experience of the CT-121 FGD Plant for 700 Mw Shinko-Kobe Electric Power Plant, Paper #27, by Yasuhiko Shimogania, et al., MEGA Symposium, Washington DC, May 22, 2003. DAQ has this document in its files.*

107 *http://www.bwe.dk/pdf/ref-11%20FGD.pdf. Several US companies such as American Electric Power (AEP) are currently installing the Chiyoda JBR scrubber. For example, AEP's Cardinal Units 1 & 2 with JBR scrubbers are scheduled to begin operating in late 2007-early 2008.*

108 *High Efficiency Double Contact Flow Scrubber for the U.S. FGD Market Paper No. 135, by Dr. Jonas S. Klingspor, et al, MEGA Symposium, Washington DC, May 22, 2003.*

109 *Id*

110 *Commercial Experience and Actual-Plant-Scale Test Facility of MHI Single Tower FGD Paper #33, by Yoshio Nakayama, et al, MEGA Symposium, Washington DC, August, 2004.*

111 *Id.*

112 *FLOWPAC — Major WFGD Advance in Flue Gas Contact Paper # 114, by Kjell Nolin, MEGA Symposium, Washington, DC, August 2004.*

113 *State of the Art Wet FGD System for High-Sulfur Fuels in Florina/Greece, by 6. Catalano, et aL, Power Gen Europe, 2005.*

114 *This significant level is itself not protective because it is based on the old lead NAAQS.*

115 *See Exhibit V-I, ETA, Data for August 2009, Table 5.4.B, Retail Sales of Electricity to Ultimate Customers by End-Use Sector, by State, Year-to-Date through August 2009 and 2008, released November 13, 2009.*

116 *See Ex. V-i, ETA, Data for August 2009, Table 2.5.B. Consumption of Coal for Electricity Generation by State by Sector, Year-to-Date through August 2009 and 2008, released November 13, 2009.*

117 *Lx. V-5, Zinga, S. M. and McDonald, A. A Portfolio of Energy Efficiency and Renewable Energy Options for East Kentucky Power Cooperative, Table 4 (Revised), Errata Sheet, Dec. 28, 2009.*

118 *Ex. V-5, at 26*

119 Actually, the SOB's calculations show CFB1's emissions as 13.595568. SOB, Appendix A.